BIENNIAL REPORT OF THE

NORTH CAROLINA UTILITIES COMMISSION

TO

THE GOVERNOR OF NORTH CAROLINA

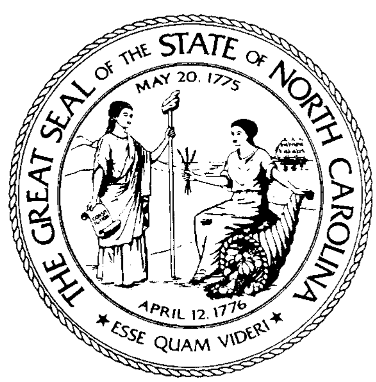
AND

THE JOINT LEGISLATIVE COMMISSION ON GOVERNMENTAL OPERATIONS

REGARDING

PROCEEDINGS FOR ELECTRIC POWER SUPPLIERS INVOLVING ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT PROGRAMS, COST RECOVERY AND INCENTIVES

(Pursuant to G.S. 62-133.9(i))



Date Due: September 1, 2013
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EXECUTIVE SUMMARY

The Utilities Commission is providing this report to the Governor and the Joint Legislative Commission on Governmental Operations pursuant to G.S. 62-133.9(i), which requires the Commission to submit a summary of proceedings conducted under G.S. 62-133.9 every two years on September 1st. The report is to cover proceedings during the preceding two fiscal years, which for this report span the time period July 1, 2011, through June 30, 2013.

In early 2012, the Commission approved rules revisions intended to strengthen the electric power suppliers' measurement and verification of the energy and capacity savings achieved by their energy efficiency (EE) and demand-side management (DSM) programs. These new rules are intended to help assure the accuracy of energy efficiency certificates (EECs) that electric power suppliers use toward their obligations under the State's renewable energy and energy efficiency portfolio standard (REPS).

During the fall of 2012 eight of the State's electric power suppliers provided assessments of the potential for DSM and EE as part of their integrated resource plans (IRPs). While those IRPs are pending before the Commission,[1] Session Law 2013-187 provides that, effective July 1, 2013, electric membership corporations (EMCs) are no longer required to participate in integrated resource planning proceedings before the Commission.

Session Law 2007-397 allows electric power suppliers to use energy savings from new EE and DSM programs toward their REPS obligations. During the two fiscal years covered by this report, the Commission approved two new programs and denied approval of two. At the time this report was published, 11 program applications filed by Dominion and Duke are pending approval.

Session Law 2007-397 further provides that, upon petition by an electric public utility, the Commission shall approve an annual rider to the utility's rates to allow it to recover all reasonable and prudent costs incurred for new DSM and EE measures. Further, the Commission may approve incentives to utilities for adopting and implementing DSM and EE programs. During the two fiscal years covered by this report, Dominion, Duke and Progress each filed annual rider applications, and those riders allow the companies to recover their DSM/EE program costs as well as incentives.

On April 10, 2012, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a motion to extend the time to initiate the formal review of Duke Energy Progress's DSM/EE rider and incentive mechanism. The review had been scheduled to begin no later than June 1, 2012. The Public Staff stated that the review of the cost recovery mechanisms for Duke and Dominion are scheduled to occur in 2014, and

[1]See Docket No. E-100, Sub 137.

contended that postponing the review of Progress's mechanism until 2014 as well would provide the Commission and the parties with a better context in which to focus on issues identified in that review process. On May 15, 2012, the Commission granted the Public Staff's motion.

Subsequently, on March 6, 2013, Duke Energy Carolinas, LLC (Duke) filed an application for a new DSM/EE cost recovery and incentive mechanism. That matter is pending before the Commission. See page 31 for more information.

At this time, the DSM/EE riders for residential customers are as follows:

Electric Public Utility	**DSM/EE Rider Charges for Residential Customer Using 1,000 kWh** (including gross receipts taxes and regulatory fee)
Dominion	$0.92/month
Duke	$1.64/month
Progress	$3.65/month

INTRODUCTION

The Utilities Commission is providing this report to the Governor and the Joint Legislative Commission on Governmental Operations pursuant to G.S. 62-133.9(i), which requires the Commission to submit a summary of proceedings conducted under G.S. 62-133.9 every two years on September 1st. The report is to cover proceedings during the preceding two fiscal years, which for this report span the time period July 1, 2011, through June 30, 2013. This report is divided into four sections, one for each of the proceeding types that the Commission conducted relative to G.S. 62-133.9 from July 1, 2011, through June 30, 2013.

G.S. 62-133.9 was enacted as part of Session Law 2007-397, which established the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) for North Carolina's electric power suppliers. Electric power suppliers can implement energy efficiency (EE) and demand-side management (DSM) measures to fulfill portions of their REPS obligations. Section 4.(a) of Session Law 2007-397, codified as G.S. 62-133.9, specifies that electric power suppliers shall use DSM and EE measures and supply-side resources to establish the least cost mix of demand reduction and generation measures that meets the electricity needs of their customers. Each electric power supplier that is required to file an Integrated Resource Plan (IRP) must include in that plan an assessment of DSM and EE and is required to submit cost-effective options that require participant incentives to the Commission for approval. Upon petition by an electric public utility, the Commission shall approve an annual rider to the utility's rates to allow it to recover all reasonable and prudent costs incurred for new DSM and EE measures, which includes only those programs instituted after January 1, 2007. Further, the Commission may approve incentives to electric public utilities for adopting and implementing new DSM and EE measures. The Commission is to determine the appropriate assignment of costs of new DSM and EE measures and shall assign those costs only to the class or classes of customers that directly benefit from the programs. Finally, none of the costs of new DSM or EE measures shall be assigned to an industrial or large commercial customer that notifies its utility that it has implemented or will implement alternative DSM and EE measures and elects not to participate in the utility's new DSM and EE measures.

Throughout this report reference is made to various Commission dockets. Readers who wish to review the official record of any proceeding may do so by visiting the Commission's web site (www.ncuc.net), selecting "Dockets" from the main menu, selecting "Docket Search," and then entering the appropriate docket number.

G.S. 62-133.8(a) contains the following definitions that apply to this report:

(2) "Demand-side management" means activities, programs or initiatives undertaken by an electric power supplier or its customers to shift the timing of electricity use from peak to non-peak demand periods. "Demand-side management" includes, but is not limited to, load management, electric system equipment and operating controls, direct load control, and interruptible load.

(4) “Energy efficiency measure” means an equipment, physical, or program change implemented after 1 January 2007 that results in less energy used to perform the same function. ‘Energy efficiency measure’ includes, but is not limited to, energy produced from a combined heat and power system that uses nonrenewable energy resources. ‘Energy efficiency measure’ does not include demand-side management.

In order to provide background and context, this report includes information for some Commission proceedings that occurred in prior fiscal years and was included in previous reports. In addition, this report acknowledges DSM/EE program applications that have been filed with the Commission recently and which fall into the next reporting period.

SECTION 1: AMENDMENTS TO THE COMMISSION'S RULES IMPLEMENTING G.S. 62-133.9

On August 24, 2010, the Commission issued an Order Requesting Comments on Measurement and Verification of Reduced Energy Consumption in Docket No. E-100, Sub 113. The Order stated that the Commission was concerned that the processes and rules then in place might not promote expeditious processing of REPS compliance reports once the general REPS compliance obligations took effect in 2012, with reports to be filed in 2013. The Commission was also concerned that its rules might be inadequate to ensure the credibility of the EE and DSM savings achieved by electric power suppliers for purposes of REPS compliance. The Order requested comments relative to four questions:

1. What kind of measurement and verification (M&V) documentation should be filed and/or made available for audit by each kind of electric power supplier that uses EE/DSM program achievements toward its general REPS obligation?
2. Whether and in what proceeding, if any, should the Commission review such M&V documentation in order to establish the savings from EE/DSM programs that may then be used by each kind of electric power supplier to comply with REPS?
3. What is the appropriate method for determining the energy savings achieved by an electric membership corporation or municipal power supplier's DSM measure or program?
4. Should electric membership corporations be required to include an M&V reporting plan in their EE/DSM program applications similar to the plan required of electric public utilities under the Commission's [then] proposed Rule R8-68(c)(3)(ii) [as set forth in its Order issued August 3, 2010]?

Comments were filed by:

Dominion North Carolina Power
Duke Energy Carolinas, LLC
ElectriCities of North Carolina, Inc.
Environmental Defense Fund
GreenCo Solutions, Inc.
North Carolina Eastern Municipal Power Agency
North Carolina Municipal Power Agency Number 1
North Carolina Sustainable Energy Association
Progress Energy Carolinas, Inc. (now Duke Energy Progress, Inc.)
Public Staff
Public Works Commission of Fayetteville
Southern Alliance for Clean Energy
Southern Environmental Law Center

On May 14, 2012, the Commission issued an Order Requiring Electric Membership Corporations and Municipal Power Suppliers to File Measurement and Verification Plans and Results for Energy Efficiency and Demand-Side Management

Programs. That Order is attached as Appendix A. The Order amended Commission Rule R8-67(b), (c), and (h) to:

1) Require each electric power supplier to include in its annual REPS compliance plan its measurement and verification plans for the EE and DSM programs that it intends to count toward REPS.
2) Require each EMC and municipal power supplier to include in its annual REPS compliance report documentation supporting the energy savings achieved in the previous year.
3) Clarify how EE and DSM savings are tracked in the North Carolina Renewable Energy Tracking System.[2]

See Appendix B for the Commission Rules that address EE and DSM:

Rule R8-60	Integrated Resource Planning and Filings
Rule R8-67	Renewable Energy and Energy Efficiency Portfolio Standard (REPS)
Rule R8-68	Incentive Programs for Electric Public Utilities and Electric Membership Corporations, Including Energy Efficiency and Demand-Side Management Programs
Rule R8-69	Cost Recovery for Demand-Side Management and Energy Efficiency Measures of Electric Public Utilities

[2] See www.ncrets.org for more information about North Carolina's renewable energy tracking system.

SECTION 2: UTILITIES' DSM AND EE ASSESSMENTS FILED AS PART OF THEIR INTEGRATED RESOURCE PLANS

G.S. 62-133.9(c) requires each electric power supplier to which G.S. 62-110.1[3] applies to include an assessment of DSM and EE in its Integrated Resource Plan (IRP).

During the fall of 2012, IRPs were filed by the following organizations:

1. Dominion North Carolina Power
2. Duke Energy Carolinas, LLC
3. EnergyUnited Electric Membership Corporation
4. Haywood Electric Membership Corporation
5. North Carolina Electric Membership Corporation
6. Piedmont Electric Membership Corporation
7. Progress Energy Carolinas, Inc. (now Duke Energy Progress, Inc.)
8. Rutherford Electric Membership Corporation

The following is a summary of each organization's DSM/EE assessment that was included in its IRP.[4]

1. Dominion North Carolina Power (Dominion)

In addition to the five new programs for Dominion approved by the Commission since the enactment of Senate Bill 3 (see page 14), the Company stated that it was considering the following future programs. (On August 20, 2013, Dominion filed eight program applications. See page 15.)

1. Commercial Duct Testing and Sealing Program
2. Commercial Energy Audit Program
3. Commercial Re-Commissioning Program
4. Commercial Refrigeration Program
5. Residential Bundle Program
    - Residential Home Energy Checkup
    - Heat Pump Upgrade Program
    - Residential Duct Testing and Sealing Program
    - Residential Heat Pump Tune-Up Program
6. Commercial Distributed Generation
7. Commercial HVAC Upgrade
8. Commercial Lighting Program

[3] G.S. 62-110.1(c) has applied to public utilities and EMCs during the period covered by this report. The following EMCs have not been subject to Commission Rule R8-60 because they are headquartered outside of North Carolina: Blue Ridge Mountain Electric Membership Corporation, Broad River Electric Cooperative, Mecklenburg Electric Cooperative, Mountain Electric Cooperative, and Tri-State Electric Membership Corporation. In addition, Session Law 2013-187, which took effect July 1, 2013, exempts all EMCs from the Commission's integrated resource planning proceedings.
[4] The Commission is reviewing these IRPs in Docket No. E-100, Sub 137, which is pending.

9. Voltage Conservation Program
10. Commercial Re-Commissioning Program
11. Commercial Data Center / Computer Room Program
12. Commercial Customer Incentive Program
13. Residential Cool Roof Program

Dominion stated that it had reviewed and rejected the following programs:

1. Commercial HVAC Tune-Up Program
2. Curtailment Service Program
3. Energy Management System Program
4. Energy Star^{R} New Homes Program
5. Geo-Thermal Heat Pump Program
6. Home Energy Comparison Program
7. Home Performance with Energy Star^{R} Program
8. In-Home Energy Display Program
9. Premium Efficiency Motors Program
10. Programmable Thermostat Program
11. Residential Heat Pump Tune Up Program
12. Refrigerator Turn-In Program
13. Residential Energy Audit Program
14. Residential Solar Water Heating Program
15. Residential Water Heater Cycling Program
16. Residential Radiant Barrier Program
17. Residential Lighting Program (Phase II)
18. Commercial Refrigeration Program

2. <u>Duke Energy Carolinas, LLC (Duke)</u>

Duke stated that its current DSM programs are:

1. Power Manager Residential Load Control
2. Interruptible Power Service
3. Standby Generator Control
4. PowerShare Non-Residential Curtailable Program
5. General Service and Industrial Optional Time-of-Use Rates[5]
6. Residential Time-of-Use Rates, Including Water Heating Direct Load Control
7. Hourly Pricing for Incremental Load

Duke estimated that its total DSM capacity would be 875 MW during the summer of 2013.

[5] For more information regarding time-of-use rates in North Carolina, see the Commission's September 1, 2008 report entitled, "Analysis of Rate Structures, Policies, and Measures to Promote Renewable Energy Generation and Demand Response in North Carolina," Commission Docket No. E-100, Sub 116.

Duke stated that its current EE programs are:

1. Non-Residential Energy Assessments
2. Residential Energy Assessments
3. Low-Income Energy Efficiency and Weatherization Program
4. Energy Efficiency Education Program for Schools
5. Residential Smart Saver[R] Energy Efficient Products Program
    a. Compact Fluorescent Lights
    b. HVAC and Heat Pump
6. Smart Saver[R] for Non-Residential Customers
7. Residential Neighborhood Program

Duke stated that it is considering adding a PowerShare CallOption 200 program that would target customers with very flexible load and with curtailment potential of up to 200 hours each year. In addition, Duke is operating several pilot programs, as indicated on page 15. Program descriptions can be found on pages 29-35 of Duke's September 1, 2012 IRP filing in Docket No. E-100, Sub 137.

Duke stated that it has developed a diverse stakeholder collaborative to help the Company identify new EE program opportunities and evaluate existing programs.

3. <u>EnergyUnited Electric Membership Corporation (EnergyUnited)</u>

EnergyUnited stated that it has the following DSM programs with customer participation as noted:

1. Residential Water Heaters (23,354 customers)
2. Coincident Peak Commercial/Industrial (29 customers)
3. Residential Air Conditioners (26,313 customers)

EnergyUnited stated that its DSM programs provide 25 MW of demand reduction, and that its new EE programs (see page 17) will provide 3.4 MW of peak reduction in 2013, growing to 8.7 MW in 2023.

4. <u>Haywood Electric Membership Corporation (Haywood)</u>

Haywood stated that it has three EE programs: Loans for High-Efficiency Heat Pumps, Hot Water Kits and a Home Energy Audit Program. Haywood is an Energy Star[R] Partner with the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy (DOE), allowing it to promote and sponsor Energy Star[R] products and EE programs. Haywood also participates in programs through GreenCo Solutions, Inc.

Haywood has load control switches on 224 air conditioners and 2,608 water heaters. Through its Smart Rate program, Haywood controls 287 electric resistance heating units and 517 appliances on time of use control. These demand response programs allow Haywood to control 2.23 MW in the summer and 4.7 MW in the winter. In addition, Haywood has 12 residential and 6 commercial members on time of use rates.

5. North Carolina Electric Membership Corporation (NCEMC)[6]

NCEMC invested in a statewide load management system on behalf of its members in the mid 1980s. That system used radio signals to control residential air conditioners and water heaters and also to control customer-owned generation. Several EMCs also operated direct load control of heating systems. As a result, NCEMC was able to reduce demand by nearly 10% or 110 MW, during peak periods, in 2007.

Because the infrastructure for its load control switches had become obsolete, NCEMC decided to dismantle its existing direct load control system by the end of 2012 and undertake new demand response programs as part of its grid modernization initiative. NCEMC expected to complete implementation of its new Control Data Settlement System (CDSS) in late 2012. CDSS will enable NCEMC's member cooperatives to leverage their advanced metering infrastructure to reduce demand and improve communications. NCEMC stated that new programs will be developed and implemented as opportunities emerge and as requested by its member cooperatives. Over the next several years, NCEMC and its members plan to use CDSS to dispatch small distributed generators that are owned by customers.

NCEMC stated that GreenCo Solutions, Inc. (GreenCo) is owned by 22 North Carolina EMCs, and GreenCo's membership overlaps with that of NCEMC. The Commission has approved 11 GreenCo EE programs. NCEMC's IRP estimates that those programs will achieve 27.8 MW of demand reduction in 2012, growing to 31.3 MW in 2020. See page 17 for more information about GreenCo's EE programs.

6. Piedmont Electric Membership Corporation (Piedmont)

In its IRP, Piedmont noted that its DSM programs allow it to control about 9.2 MW of load via load control switches on air conditioners and water heaters. Piedmont also has 519 residential and 24 commercial and industrial customers participating in time-of-use rates.

Piedmont stated that it offers EE loans to its members, most of which are used to replace inefficient heat pumps with high-efficiency heat pumps. They make about 70 loans each year. They also offer a discount rate to members whose homes meet certain EE standards. Piedmont offers free residential energy audits, free evaluations of members' HVAC systems, audits for commercial and industrial customers, school programs, a speakers' bureau, and education via its newsletter, brochures and web site. Piedmont recently added a residential duct blasting test and an infrared thermal imaging camera to its auditing capabilities.

[6] See Appendix D for a list of NCEMC's members.

Piedmont will participate in EE programs offered via GreenCo. Piedmont stated that it is an Energy Star® Partner with the U.S. Environmental Protection Agency and the U.S. Department of Energy through which it will promote Energy Star® EE products and programs. Piedmont's smart grid meter deployment was completed in August of 2009, allowing it to offer a pre-pay program and an online daily energy monitoring system to all of its members. In February of 2009 it conducted a solar water heater pilot rebate program, and in May of 2009 it implemented the program by offering a $500 rebate to members who installed a solar water heater by August 2010. In February of 2010 Piedmont began a compact fluorescent light rebate program, and in September of 2009 through July of 2010 Piedmont ran an electric water heater kit program. Piedmont has launched TogetherWeSave.com, a tool that provides members with money saving tips and practices for saving energy.

7. <u>Duke Energy Progress, Inc. (Progress)</u>

Progress stated that its EE/DSM portfolio consists of the following "new" programs, that is, programs Progress initiated after the passage of Senate Bill 3 in 2007:

1. Residential Home Energy Improvement
2. Residential Home Advantage (closed to new participants)
3. Residential New Construction
4. Residential Neighborhood Energy Saver (Low-Income)
5. Residential Lighting
6. Residential Appliance Recycling
7. Residential Energy Efficient Benchmarking
8. Commercial, Industrial, and Governmental EE
9. Small Business Energy Saver
10. Residential EnergyWise Home℠
11. Commercial, Industrial, and Government Demand Response Automation
12. Distribution System Demand Response

Program descriptions can be found on pages E-1 through E-9 of Progress's September 4, 2012 IRP filing in Docket No. E-100, Sub 137.

In addition, Progress continued to operate two EE programs and five DSM programs that were initiated prior to Senate Bill 3:

1. Energy Efficient Home Program
2. Time-of-Use Rates
3. Thermal Energy Storage Rates
4. Real-Time Pricing for Large General Service
5. Curtailable Rates for Industrial and Commercial Customers
6. Voltage Control

Progress stated that it had commissioned a new EE market potential study to obtain new estimates of the technical, economic and achievable potential for EE in its service area. The report was completed June 5, 2012, and shows that, via programs established since 2007, Progress estimates that it will reduce it summer peak by 479 MW in 2013, growing to a 1,073-MW peak reduction in 2027. The combined impact of the programs Progress had in place before Senate Bill 3, and since Senate Bill 3 is 828 MW peak demand savings in 2013, growing to 1,441 MW of peak demand savings in 2027.

Finally, Progress stated that it offers the following informational and educational programs:

1. Customized Home Energy Report
2. On Line Account Access
3. "Lower My Bill" Toolkit
4. Energy Saving Tips
5. Energy Resource Center
6. Commercial, Industrial, and Governmental Account Management
7. eSMART Kids Website
8. Community Events

Progress reported the results of an investigation into the question of whether activating DSM resources during times of high system load could achieve lower fuel costs. Progress concluded that,

> ... dispatching DR [demand response] resources purely for economics poses the risk of overuse, such as using it for three or more consecutive days when a hot, dry spell settles in the area and causes peak load conditions that require the use of expensive oil CT generation. However, these peak usage periods are also the times when customers most need cooling from their air conditioning equipment, so excessive curtailments of that end-use can cause sufficient customer discomfort and dissatisfaction that they decide to leave the program.

In summary, the Company reported that, "program activations, whether for economics or reliability, must avoid overuse, minimize customer discomfort associated with load control and ultimately keep customers from leaving the program."

8. <u>Rutherford Electric Membership Corporation (Rutherford)</u>

Rutherford's IRP stated that it has the following DSM programs:

1. Controllable Customer-Owned Generation (13.5 MW)
2. Time-of-Use Rates (9 customers)
3. Switches to Control Air Conditioners (7,934) and Water Heaters (12,921)

Rutherford stated that its switches can provide 7.5 MW of demand reduction.

In terms of EE, Rutherford stated that it had purchased 9,000 compact fluorescent light bulbs for its October 2011 annual meeting and provided them to its members. Rutherford estimated that this effort saved 414 kW of demand.

Rutherford stated that in 2008 it deployed an automated meter reading system that provides two-way communications to all meters and collects daily meter readings. In 2010, Rutherford added web-based software that allows residential consumers to view daily energy use, receive daily emails and texts regarding energy use, and receive an alarm if their energy use exceeds their budget. This energy portal is accessed 50 times a week, on average. In 2013 the portal will be upgraded, and commercial accounts will then be accessible as well. Rutherford stated that it considers this effort to be consumer education, rather than EE.

SECTION 3: NEW DSM AND EE PROGRAMS

Senate Bill 3 allows electric public utilities to use energy savings from new EE programs toward their REPS obligations. Similarly, electric membership corporations (EMCs) and municipalities may use energy savings from EE and DSM programs toward their REPS obligations. Electric public utilities and EMCs must file new program applications with the Commission. Programs initiated after the passage of Senate Bill 3 are considered "new."

1. Dominion's New DSM and EE Programs

The chart below lists Dominion's New DSM and EE Programs.

On September 1, 2010, Dominion proposed a commercial distributed generation (CDG) program. Under the CDG program, commercial and industrial customers would commit a minimum of 200 kW of backup generation for dispatch in response to load control events initiated by Dominion for up to 120 hours per year in exchange for an incentive payment. Dominion proposed to use a third-party vendor to implement the program. The vendor would dispatch the backup generation and provide unit monitoring, maintenance and operation services. Incentive payments for participation in the CDG program would be paid by Dominion to the participating customer through the third-party vendor. On September 14, 2011, the Commission denied approval of the program because the Commission concluded that the program was designed to incent the construction of new electric generation facilities.

<table>
<tr><th colspan="2">EE Programs[7]</th><th>Procedural History</th></tr>
<tr><td>1</td><td>Residential Low-Income Program</td><td rowspan="4">Filed 9/1/2010
Approved 2/22/2011</td></tr>
<tr><td>2</td><td>Commercial HVAC Upgrade Program (suspended 8/14/2012, re-filed 8/20/2013)</td></tr>
<tr><td>3</td><td>Residential Lighting Program[8]</td></tr>
<tr><td>4</td><td>Commercial Lighting Program (suspended 8/14/2012, re-filed 8/20/2013)</td></tr>
<tr><th colspan="3">DSM Programs[9]</th></tr>
<tr><td>5</td><td>Residential Air Conditioner Cycling Program</td><td>Filed 9/1/2010
Approved 2/22/2011</td></tr>
<tr><td>6</td><td>Commercial Distributed Generation Program</td><td>Filed 9/1/2010
Denied 9/14/2011</td></tr>
</table>

In total, Dominion planned to spend $187 million on these programs from 2011 through 2015 on a system-wide basis. North Carolina's share of that spending would be approximately 6.6%, or $12 million.

[7] Docket No. E-22, Subs 463, 467, 468 and 469.
[8] In its August 31, 2012 Integrated Resource Plan, Dominion stated that as of December 31, 2011, its residential lighting program was concluded due to increased bulb efficiency standards that became effective January 1, 2012, as mandated by the Energy Independence and Security Act of 2007.
[9] Docket No. E-22, Subs 465 and 466.

On August 20, 2013, Dominion filed applications for the following eight programs, two of which had been previously approved and then suspended, and all of which are pending before the Commission:

1. Commercial HVAC Upgrade Program (Docket No. E-22, Sub 467)
2. Commercial Lighting Program (Docket No. E-22, Sub 469)
3. Non-Residential Energy Audit Program (Docket No. E-22, Sub 495)
4. Non-Residential Duct Testing and Sealing Program (Docket No. E-22, Sub 496)
5. Residential Duct Testing and Sealing Program (Docket No. E-22, Sub 497)
6. Residential Home Energy Check Up Program (Docket No. E-22, Sub 498)
7. Residential Heat Pump Tune Up Program (Docket No. E-22, Sub 499)
8. Residential Heat Pump Upgrade Program (Docket No. E-22, Sub 500)

2. Duke's New DSM and EE Programs

The charts below list Duke's new pilot programs, EE programs, and DSM programs.

Pilot Programs		**Procedural History**	**Program Costs and Time Period**
1	Residential Energy Management System Pilot[10]	Filed 2/11/2009 Approved 3/10/2009 Extension Filed 6/2/2010 Extension Approved 6/22/2010	Unknown; Duke will not seek cost recovery or incentives for this pilot. 2009-9/30/2011
2	Residential Retrofit Pilot[11]	Filed 6/7/2010 Approved 1/25/2011	$850,000 2011-2012
3	Smart Energy Now Pilot[12] (Envision Charlotte)	Filed 10/1/2010 Approved 2/14/2011	$2,729,988 2011-2013
4	Home Energy Comparison Report Pilot[13]	Filed 6/4/2010 Withdrawn 11/24/2010	NA

[10] Docket No. E-7, Sub 906.
[11] Docket No. E-7, Sub 952.
[12] Docket No. E-7, Sub 961.
[13] Docket No. E-7, Sub 954. In withdrawing the pilot, Duke stated that it intended to file a similar program in 2011.

EE Programs		Procedural History	Program Costs and Time Period
1	Residential Energy Assessments	These programs were filed in the "save-a-watt" docket, E-7, Sub 831. Filed 5/7/2007 Approved 2/26/2009	$15.5 million 2009-2013
2	Residential Smart Saver		$22.0 million 2009-2013
3	Low Income Services		$24.5 million 2009-2013
4	Energy Efficiency Education Schools Program		$33.7 million 2009-2013
5	Non-Residential Energy Assessments		$50.6 million 2009-2013
6	Non-Residential Smart Saver		
7	Residential My Home Energy Report[14]	Filed 6/7/2012 Approved 9/11/2012	$25.5 million Over five years
8	Residential Neighborhood Low-Income Program[15]	Filed 2/22/2012 Approved 6/19/2012	$6.8 million Over four years
9	Residential Appliance Recycling Program	Filed 2/22/2012 Approved 7/17/2012	$9.6 - $10.7 million over four years
DSM Programs			
10	Residential Power Manager	Filed 5/7/2007 Approved 2/26/2009	$18.9 million 2009-2013
11	Non-Residential PowerShare Call Option	Filed 5/7/2007 Approved 2/26/2009 Filed 6/7/2010 Approved 3/31/2011	$34.6 million 2009-2013 $9.3 million for four years

On March 6, 2013, Duke filed an application for approval of a new DSM and EE cost recovery and incentives mechanism and a portfolio of new DSM and EE programs. The portfolio includes all of the 11 current programs listed above (some with modifications), as well as two new programs and one new pilot: Multi-Family EE, Non-Residential Smart Saver EE Information Technology Products, and Energy Management Systems Pilot.

Duke proposed to spend $424.6 million from 2014 through 2017 on its portfolio of DSM and EE programs. The Commission's decision regarding Duke's proposed portfolio of DSM and EE programs is pending in Docket No. E-7, Sub 1032, which is Duke's application for a new incentive mechanism. (See page 31 for more information.)

[14] Docket No. E-7, Sub 1015.
[15] Docket No. E-7, Sub 1004.

3. EnergyUnited's New EE Programs

The following chart lists EnergyUnited's new DSM/EE programs. EnergyUnited did not file any additional program applications during the period covered by this report.

EE Programs[16]		Procedural History	Program Costs and Time Period
1	Residential Heat Pump Rebate Program	Filed 6/23/2009 Approved 9/22/2009	$584,953 2009-2013
2	Commercial and Industrial Lighting Program		$363,626 2009-2013

4. GreenCo's New EE Programs

On January 29, 2010, GreenCo filed for approval of eleven EE programs, as listed below. (Appendix C lists the GreenCo members.) GreenCo stated that the decision to offer a particular EE program rests with the board of directors of each member. Similarly, each board of directors determines the amount of incentive paid by that EMC to its customers who participate in a particular EE program.

In its September 4, 2012 REPS compliance plan, GreenCo estimated that the EE programs implemented by its members would save 139,290 MWh in 2012, growing to 185,076 MWh of savings in 2014.

EE Programs[17]		Procedural History	Program Costs and Time Period[18]
1	Agricultural EE Program	Filed 1/29/2010 Approved 8/23/2010	$170,249
2	Commercial EE Program		$661,612
3	Commercial New Construction Program		$32,733
4	Community Efficiency Campaign		$4,184,936
5	Low-Income Community Efficiency Program		$296,031
6	Energy Cost Monitor Program		$853,245
7	Energy Star^R Appliances Program		$299,066
8	Energy Star^R Lighting Program		$2,126,026

[16] Docket No. EC-82, Sub 10.
[17] Docket No. EC-83, Sub 0.
[18] GreenCo stated that all of the programs would operate on an on-going basis and provided annual costs for each program through 2017. The costs listed here are GreenCo's cost estimates for 2011.

9	Energy Star New Home Construction Program	Filed 1/29/2010 Approved 8/23/2010	$580,029
10	Refrigerator/Freezer Turn-in Program		$16,888
11	Water Heater Efficiency Program		$576,096

GreenCo did not file any additional program applications during the period covered by this report.

5. Progress's New DSM and EE Programs

During the two fiscal years covered by this report, Progress filed for approval of the following new programs:

EE Programs		**Procedural History**	**Program Costs and Time Period**
1	Residential Service Pre-Pay Pilot[19]	Filed 2/17/2012 Denied 6/13/2012	NA
2	Residential New Construction[20]	Filed 5/31/12 Approved 10/2/2012	$31.2 million over three years
3	Small Business Energy Saver[21]	Filed 5/31/2012 Approved 11/5/2012	$12.9 million over three years

The Commission denied Progress's request for a Residential Service Pre-Pay Pilot because the Commission was not persuaded that it would lead to a cost-effective EE program. The pilot would have required participants to incur payment processing fees, and a similar pilot that Progress conducted in 2001 found that pre-pay participants made an average of five payments a month. Therefore, the Commission found that the proposed pilot would be unlikely to be cost-effective from the participant's perspective.

During previous years, Progress filed for approval of the following programs:

EE Programs[22,23]		**Procedural History**	**Program Costs and Time Period**
1	Residential Lighting Program	Filed 9/1/2009 Approved 11/25/2009	$12,018,000 2009-2011
2	Neighborhood Energy Saver Program (Low-Income)	Filed 6/4/2009 Approved 8/3/2009	$10,088,000 2009-2013
3	Appliance Recycling Program	Filed 12/22/2009 Approved 3/22/2010	$11,181,077 2010-2014
4	Residential Service EE Benchmarking Program	Filed 12/20/2010 Approved 4/27/2011	$2,356,704 2011-2013
5	Compact Fluorescent Light Pilot	Filed 8/28/2007	$277,090

[19] Docket No. E-2, Sub 1011.
[20] Docket No. E-2, Sub 1021.
[21] Docket No. E-2, Sub 1022.
[22] Docket No. E-2, Subs 950, 952, 970, and 989.
[23] Docket No. E-2, Subs 908, 926, 928, 935, 936, 937, 938, and 952.

		Approved 9/19/2007	2007-2008
6	Commercial, Industrial, and Governmental Energy Efficiency	Filed 5/1/2008 & 10/31/2008 Approved 10/14/2008 & 4/21/2009	$59 million 2009-2013
7	Residential Home Advantage	Filed 5/1/2008 Approved 10/14/2008	$11.7 million 2008-2012
8	Residential Home Energy Improvement	Filed 10/31/2008 Approved 4/30/2009	$20 million 2009-2013
9	Residential Solar Water Heating Pilot	Filed 10/31/2008 Approved 4/30/2009	$490,000 2009-2010
10	Neighborhood Energy Saver (low-income customers)	Filed 6/4/2009 Approved 8/3/2009	$10 million 2009-2013
11	Distribution System Demand Response (DSDR)	Filed 4/29/2008 Approved 6/15/2009	$260 million 2007-2012

DSM Programs[24,25]			
1	Commercial, Industrial, and Governmental Demand Response	Filed 6/4/2009 Approved 8/3/2009	$12,893,000 2009-2013
2	Residential EnergyWise™	Filed 4/29/2008 Approved 10/14/2008	$55.4 million 2008-2012
3	Commercial, Industrial and Governmental Demand Response Automation	Filed 6/4/2009 Approved 8/3/2009	$12.9 million 2009-2013

On April 29, 2008, Progress filed an application for approval of its Distribution System Demand Response (DSDR) program. By orders dated June 15, 2009, and November 25, 2009,[26] the Commission approved DSDR as an EE program. Under this program, Progress is investing $260 million in advanced distribution technology that will let the Company reduce customer energy demand by reducing the voltage along its distribution feeders. Progress completed implementation of DSDR in late 2012. This program will allow Progress to reduce its peak demand by about 236 MW.

Progress's DSDR program presented significant policy issues for the Commission. One issue regards whether this program meets the statutory definition of a DSM program or as an EE program. The Commission found that DSDR is an EE program because it will reduce customers' energy consumption during peak periods; i.e., it "results in less energy [being] used to perform the same function," which is the statutory definition of an EE program. The other policy issue presented by the DSDR program relates to cost allocation. The Commission initially concluded that DSDR's costs should be recovered from all retail customers that benefit; that is, all retail customers that receive power via Progress's distribution system, regardless of the "opt out" provision for industrial and large commercial customers contained in

[24] Docket No. E-2, Subs 953.
[25] Docket No. E-2, Subs 927 and 953.
[26] Docket No. E-2, Sub 926.

G.S. 62-133.9(f). However, upon reconsideration, the Commission found that Progress's industrial and large commercial customers may opt out of participation in all Commission-approved DSM and EE programs offered by the utility, including the DSDR program.

SECTION 4: COMMISSION PROCEEDINGS REGARDING DSM/EE COST RECOVERY AND INCENTIVES

DSM/EE Rider Proceedings for Dominion North Carolina Power

1. Dominion's First DSM/EE Cost Recovery and Incentives Proceeding[27]

On September 1, 2010, Dominion filed its first application for an annual DSM and EE cost recovery rider. Dominion initially requested a total annual revenue increase of $1,841,000, effective January 1, 2011, to be recovered through its proposed DSM/EE rider, Rider C. Dominion requested cost recovery and utility incentives relative to six DSM/EE programs:

1) Residential Low Income
2) Residential Air Conditioning Cycling
3) Commercial Distributed Generation
4) Commercial HVAC Upgrade
5) Residential Lighting
6) Commercial Lighting

Nucor-Steel Hertford and the Attorney General filed interventions. On March 2, 2011, the Public Staff and Dominion filed an Agreement and Stipulation of Settlement. Among the more important issues addressed in the Settlement are the following:

1) Dominion's annual revenues from the rider would be $1,147,991 (excluding gross receipt taxes and regulatory fees).
2) The parties will review the settlement terms and conditions at least every three years and will submit any proposed changes to the Commission for approval.
3) The net impact on the monthly bill of a typical residential customer using 1,000 kWh of electricity would be $0.53 as compared to $0.99 under Dominion's initial application.
4) Dominion would collect from customers its DSM and EE program costs as well as two financial incentives: three year's worth of net lost revenues and a program performance incentive (PPI). The PPI would be 8% of a DSM program's estimated net savings and 13% of an EE program's estimated net savings. Research and development activities, as well as programs that promote general awareness and education regarding DSM and EE, would be ineligible for incentives.
5) The parties will work together to determine a reasonable and appropriate jurisdictional cost allocation method to apply in future DSM/EE cost recovery proceedings and will present their joint or individual recommendations to the Commission in the DSM/EE cost recovery proceeding filed in 2011.

[27] Docket No. E-22, Sub 464.

6) Beginning with its rider filing in 2012, Dominion will perform biennial cost-effectiveness evaluations for each of the DSM and EE programs that have been implemented for at least 12 months.

Under the Settlement, customer rider charges, including gross receipts taxes, would be as follows:

Residential	0.053 cents/kWh
Small General Service and Public Authorities	0.024 cents/kWh
Large General Service	0.026 cents/kWh

On April 13, 2011, the Commission conducted an evidentiary hearing and took testimony from expert witnesses.

On May 31, 2011, the Attorney General filed a brief stating that, while Dominion should be entitled to earn a reasonable profit on its DSM and EE programs, the automatic receipt of net lost revenues would provide an unreasonable level of profit for the Company.

On October 14, 2011, the Commission issued an Order approving the Settlement.

2. Dominion's Second DSM/EE Cost Recovery and Incentives Proceeding[28]

On August 26, 2011, Dominion filed a DSM/EE rider application in which it sought to recover $2 million for the following programs:

1. Low Income Program
2. Air Conditioner Cycling Program
3. Commercial HVAC Upgrade Program
4. Residential Lighting Program
5. Commercial Lighting Program

On November, 4, 2011, Dominion filed an addendum to the agreement that it had reached with the Public Staff in the 2010 DSM/EE proceeding. The addendum addressed the fact that the Virginia State Corporation Commission had imposed cost limits or caps on Dominion's DSM and EE expenditures. These caps made it possible that Dominion would limit the participation of its Virginia customers in some of its DSM and EE programs. If this were to occur, the addendum committed Dominion to meet with the Public Staff to address whether the allocation of costs between the two jurisdictions needed to be adjusted.

On December 13, 2011, the Commission issued an Order approving Dominion's rider application and authorizing the following DSM/EE rider charges, including gross receipts taxes, effective January 1, 2012:

[28] Docket No. E-22, Sub 473.

Residential	0.086 cents/kWh
Small General Service and Public Authorities	0.040 cents/kWh
Large General Service	0.038 cents/kWh

The Commission's Order required Dominion to provide, in future DSM/EE rider applications, a list of the Company's event sponsorship and consumer education and awareness initiatives. In addition, the Order required Dominion to revise its evaluation, measurement and verification reports to include sufficient information and an analysis of the gross and net savings and costs of the programs such that the Public Staff and the Commission will be able to fully evaluate net-to-gross adjustments made by Dominion to determine each program's actual savings.

3. Dominion's Third DSM/EE Cost Recovery and Incentives Proceeding[29]

On August 21, 2012, Dominion filed its third DSM/EE rider application, requesting recovery of $2,065,163 for incentives and costs related to the following programs:

1. Low Income Program
2. Air Conditioner Cycling Program
3. Commercial HVAC Upgrade Program
4. Residential Lighting Program
5. Commercial Lighting Program

The Public Staff submitted detailed testimony regarding concerns they had with Dominion's evaluation, measurement and verification (EM&V) for its programs. On November 14, 2012, the Public Staff filed a supplemental affidavit stating that the Public Staff and Dominion had agreed that, in lieu of conducting EM&V regarding "snapback" (the shift of demand from on-peak to off-peak periods) for DSM events, Dominion would provide operational data, including interval meter data, for the samples selected to be evaluated for the AC Cycling Program during the 2010, 2011, and 2012 cooling seasons.

The Commission held its evidentiary hearing on November 20, 2012. On December 14, 2012, the Commission issued its Order approving the following rider charges, including gross receipts tax, effective January 1, 2013:

Residential	0.092 cents/kWh
Small General Service and Public Authorities	0.047 cents/kWh
Large General Service	0.051 cents/kWh

In that Order the Commission found that Dominion's EM&V analysis and reports were reasonable for the purposes of the proceeding, but that the recommendations from the Public Staff for future EM&V reports were also reasonable. To the extent that the benefits of additional EM&V exceed the costs, Dominion should comply with the Public Staff's recommendations.

[29] Docket No. E-22, Sub 486.

Finally, the Commission required Dominion to file a proposal within 60 days concerning the future of two programs that had been suspended:[30] Commercial HVAC and Commercial Lighting. On February 12, 2013, Dominion filed a proposal for how to allocate the costs of these programs, assuming they were re-launched solely in North Carolina, stating that the Public Staff agreed with Dominion's proposal. On April 29, 2013, the Commission approved the assignment of 100 percent of the program costs to North Carolina, conditional upon: (1) Dominion submitting updated program applications, including cost-effectiveness results; (2) the Commission approving the re-filed North Carolina-only programs; (3) Dominion and the Public Staff submitting a signed agreement regarding the cost allocation; and (4) Dominion providing a witness in its subsequent rider proceedings who could address cost recovery for North Carolina-only programs.

4. Dominion's Fourth DSM/EE Cost Recovery and Incentives Proceeding[31]

On August 20, 2013, Dominion filed its fourth DSM/EE incentives and cost recovery rider application in which it seeks to recover costs and incentives for the following existing programs:

1. Low Income Program
2. Air Conditioner Cycling Program

Dominion also sought recovery of costs for the following new programs, and filed separate program applications for each of them:

3. Non-Residential Energy Audit Program (Docket No. E-22, Sub 495)
4. Non-Residential Duct Testing and Sealing Program (Docket No. E-22, Sub 496)
5. Residential Home Energy Check-Up Program (Docket No. E-22, Sub 498)
6. Residential Duct Testing and Sealing Program (Docket No. E-22, Sub 497)
7. Residential Heat Pump Tune-Up Program (Docket No. E-22, Sub 499)
8. Residential Heat Pump Upgrade Program (Docket No. E-22, Sub 500)

Contemporaneously, the Company re-filed program applications for North Carolina-only Commercial HVAC Upgrade and Commercial Lighting Programs. Dominion has requested that these programs be approved to begin accepting participants January 1, 2014.

In its rider application, Dominion seeks recovery of $2,411,089. As proposed, Dominion's rider would result in the following charges, which include gross receipts taxes.

[30] On August 14, 2012, the Commission approved the suspension of these programs in Docket No. E-22, Subs 467 and 469. Dominion requested the suspensions because the Virginia State Corporation Commission had disapproved Dominion's spending for these programs effective April 30, 2012.
[31] Docket No. E-22, Sub 494.

Residential	0.093 cents/kWh
Small General Service and Public Authorities	0.084 cents/kWh
Large General Service	0.106 cents/kWh

This matter remains pending before the Commission, which will schedule an evidentiary hearing for November of 2013.

DSM/EE Rider Proceedings for Duke Energy Carolinas, LLC

1. Duke's First DSM/EE Cost Recovery and Incentives Proceeding[32]

On May 7, 2007, Duke requested approval of a "save-a-watt" approach to DSM and EE programs. In addition to approval of the new DSM and EE programs discussed in Section 3 of this report, Duke requested approval of an EE rider[33] to compensate and reward it for verified EE results and to recover the amortization of, and a return on, 90% of the generation costs avoided by those programs. Under Duke's proposal, the Commission would establish the rider and adjust it annually based upon updated projections of Duke's incremental avoided costs and the actual energy savings achieved by Duke's programs. Duke argued that recovery of 90% of avoided costs would provide an appropriate incentive to Duke because it would let the Company earn a rate of return similar to investments in generation, yet it would offer a 10% discount to customers compared to the investment and the ongoing operational costs of electric generation facilities.

The Commission conducted evidentiary hearings beginning July 28, 2008. Many organizations intervened in opposition to Duke's proposal, including the Public Staff and the Attorney General. Arguments opposing Duke's proposal included the following: (1) it would be too expensive for ratepayers; (2) it would produce greater financial returns for Duke than are reasonable and necessary to encourage Duke to pursue DSM and EE; (3) Duke's avoided-cost-based compensation mechanism would be a major and unjustified departure from traditional rate regulation; (4) under save-a-watt, DSM would be much more profitable than EE for Duke; (5) save-a-watt would be vastly different from and inferior to compensation methods used with electric utilities in other states; and (6) Duke's proposed accounting procedures and reporting format were flawed.

In a February 26, 2009 Order, the Commission found that the evidence and arguments of the intervenors in opposition to save-a-watt were largely based on concerns regarding the earnings Duke would experience. "Such earnings, however, were not quantified and/or expressed, in most instances, in conventional terms of art customarily employed in rate base, rate-of-return regulation, such as 'overall rate of return' and/or 'return on common equity.'" The Commission, therefore, issued an Order: (1) approving Duke's proposed EE and DSM programs; (2) requesting more data regarding the profitability of save-a-watt for Duke by March 31, 2009; and (3) allowing

[32] Docket No. E-7, Sub 831.

[33] Duke refers to its DSM/EE rider as "Rider EE"; however, the rider includes customer charges intended to recover Duke's costs and utility incentives for both DSM and EE programs.

Duke's rider to become effective, subject to refund. Effective June 1, 2009, the following customer rider charges, including gross receipts taxes and regulatory fees, took effect:

Residential	0.0382 cents/kWh
Non-Residential	0.0068 cents/kWh

On June 12, 2009, Duke, the Public Staff, and a group of Environmental Intervenors[34] (collectively, the Stipulating Parties) filed an Agreement and Joint Stipulation of Settlement (Settlement) that would compensate Duke for successful DSM and EE programs based on a discount to the avoided costs of a power plant, rather than based on Duke's actual program costs. However, the Settlement modified Duke's original proposal. The Settlement proposed a four-year limited term pilot and included the separate recovery of net lost revenues for a limited time period. In addition, the Settlement provided a series of annual true-ups to update Duke's revenue requirements (and rider charges) based on actual customer program participation. The final avoided-cost related revenue requirements over the four-year period would be based on Duke's measured and verified savings achieved, subject to an earnings cap, with earnings measured as the excess of revenue requirements over DSM/EE program costs.

Under the "modified save-a-watt approach" set forth in the Settlement, Duke would be compensated on 75% of avoided capacity costs for DSM programs and 50% of the net present value (NPV) of the avoided energy costs plus 50% of the NPV of avoided capacity costs for EE programs. In addition, the Settlement contained a "pay for performance" feature by which Duke's compensation would depend upon actual DSM and EE savings achieved and verified by an independent third party. Duke would remain at risk, based upon its actual performance, for recovery of its DSM and EE costs, as well as any management incentive. The Settlement included performance targets such that Duke would receive a higher level of incentive based on how well it achieved DSM and EE savings that resulted in bill savings for customers. Duke increased the amount of EE avoided-cost savings it would target to achieve. The Company's revenues recovered on the basis of percentages of avoided costs would be limited to the amount needed to produce an after-tax return on program costs between 5% and 15%, depending on Duke's success in reaching a targeted aggregate EE and DSM avoided-cost savings level. In addition, the amount of net lost revenues Duke would be allowed to recover would be limited to those incurred within 36 months of implementation of a particular measure, and recovery of net lost revenues would be separate and, hence, more transparent than under Duke's initial proposal. The Settlement stated that the modified save-a-watt approach would shield ratepayers from the risk of tying rates to unknown and variable supply-side avoided costs by locking in the avoided costs (with certain exceptions).

[34] The Environmental Intervenors included the Southern Alliance for Clean Energy, the Environmental Defense Fund, the Natural Resources Defense Council, and the Southern Environmental Law Center.

Under the Settlement, based on 85% achievement of its DSM/EE targets, Duke stated that customer rider charges, including gross receipts taxes and regulatory fees, would be:

	Year 1	Year 2	Year 3	Year 4
Residential	0.1206 cents/kWh	0.1749 cents/kWh	0.2787 cents/kWh	0.4027 cents/kWh
Non-Residential	0.0428 cents/kWh	0.0579 cents/kWh	0.0969 cents/kWh	0.1339 cents/kWh

The Commission required the Stipulating Parties to file expert witness testimony to explain the Settlement and also required the filing of other information and analyses. An evidentiary hearing was held August 19, 2009.

On February 9, 2010, the Commission issued an Order Approving Agreement and Joint Settlement Subject to Certain Commission-Required Modifications and Decisions on Contested Issues. The Commission concluded that the level of avoided-cost recovery proposed in the Settlement was reasonable and in the public interest, and also approved the recovery of net lost revenues resulting from EE measures, but not those resulting from DSM,[35] as contemplated by the Stipulating Parties.

In its February 9, 2010 Order, the Commission made several modifications to the net lost revenues provision of the Settlement: (1) programs or measures with the primary purpose of promoting general awareness and education regarding EE, as well as research and development activities, would be ineligible for a net lost revenue incentive; (2) pilot programs would also be ineligible for a net lost revenue incentive, unless the Commission approved Duke's specific request that a pilot program be eligible for net lost revenues when Duke sought approval of that pilot program; and (3) utility activities should be closely monitored by Duke to determine if they caused customers to increase demand or consumption, and Duke should identify and track its activities that cause customers to increase demand or consumption, whether or not those activities are associated with DSM or EE programs, so that they may be evaluated by the parties and the Commission for possible confirmation as "found revenues."[36] Furthermore, the Commission concluded that its approval of the "recovery of net lost revenues" means the recovery of revenue losses, net of all marginal costs actually avoided, including energy-related and non energy-related costs.

With respect to the issue of cost allocations to various customer classes, in its February 9, 2010 Order, the Commission concluded: (1) that the costs of Duke's DSM and EE programs should be allocated to the North Carolina and South Carolina retail

[35] The Settlement erroneously did not reflect the parties' intent that recovery of net lost revenues was limited to those from EE programs. The Commission's February 9, 2010 Order corrected this error and expressly limited the recovery of net lost revenues to those associated with EE programs.

[36] The issue of "found revenues" relates to the concern that a utility would take the electricity "freed up" by its retail EE and DSM programs and sell it to wholesale customers. It would be inappropriate to compensate the utility for the revenue losses caused by the EE and DSM programs, if the utility in fact makes up for those revenue losses by selling the electricity elsewhere.

jurisdictions; (2) that such costs should be recovered from only the class or classes of retail customers to which the programs are targeted; and (3) that no costs should be allocated to the wholesale jurisdiction. Furthermore, the Commission determined that the reduced energy consumption resulting from the implementation of EE measures thus paid for by Duke's retail customers should be used solely for Duke's REPS compliance obligation.

On March 10, 2010, Duke filed a motion for clarification and reconsideration of the February 9, 2010 Order with respect to the issue of net lost revenues. Duke requested clarification and reconsideration regarding the Commission's requirement that Duke identify and track its activities that might be evaluated for possible confirmation as "found revenues." The Commission received comments and reply comments, and on July 7, 2010, issued an Order Denying Motion for Clarification and Reconsideration.

As a result of the Commission's December 14, 2009 Notice of Decision, Duke's new rider amounts were effective January 1, 2010 (including gross receipts taxes and regulatory fee):

Residential	0.1206 cents/kWh
Non-residential	0.0428 cents/kWh

2. Duke's Second DSM/EE Cost Recovery and Incentives Proceeding[37]

On March 5, 2010, Duke filed its second application for approval of a DSM/EE cost recovery rider. The Public Staff, the Attorney General, and Carolina Utility Customers Association, Inc. (CUCA), intervened, and the Commission held an evidentiary hearing on June 8, 2010.

Public Staff witness Michael C. Maness testified that the rates proposed by Duke were essentially the same as those that had been estimated for Year 2 during the previous Duke rider proceeding and that Duke's updates to those rates were appropriate.[38] Consequently, the revenue requirements calculated by Duke in its second rider proceeding for Year 2 were essentially the same as those estimated for Year 2 at the time of the 2009 Settlement and the Commission's February 9, 2010 Order in Duke's first rider proceeding. The Public Staff reviewed the changes from the 2009 Settlement, found them to be reasonable, and recommended that the Commission approve Duke's second proposed rider, subject to appropriate true-up in future cost recovery proceedings.

In its August 3, 2010 Order Approving DSM/EE Rider and Requiring Filing of Customer Notice Proposal, the Commission agreed that Duke's second rider charges

[37] Docket No. E-7, Sub 941.

[38] Duke's updates included using the latest North Carolina retail kWh sales forecast; updating calculations of net lost revenues to subtract variable O&M; correcting an error in applying gross receipts taxes to net lost revenues; and separating non-residential billing factors into EE and DSM components to accommodate customer participation elections.

were calculated in accordance with the Settlement, as modified by the Commission, and that the proposed rider should be approved, subject to appropriate true-ups in future proceedings. Consequently, during the rate period January 1, 2011, through December 31, 2011, the rider charges (including gross receipts taxes and regulatory fee) were as follows:

Residential	0.1702 cents/kWh
Non-Residential, DSM or EE, Vintage Year 1[39]	0.0031 cents/kWh
Non-Residential, EE, Vintage Year 2[40]	0.0257 cents/kWh
Non-Residential, DSM, Vintage Year 2[41]	0.0297 cents/kWh

The number of categories of non-residential rider rates increased from one to three as a result of Duke's request for flexibility to manage its large customer "opt outs."[42] G.S. 62-133.9(f) provides that large commercial and all industrial customers may "opt out" of the costs of new DSM and EE programs if the customer elects not to participate in the programs and pursues similar efforts on its own. The waiver granted by the Commission allows those non-residential Duke customers that are eligible to opt out the flexibility to opt out of either or both of the DSM and EE program categories for one or more years and then to opt back into either or both of the categories. If a customer opts back into the DSM category, it cannot opt back out for three years; however, a customer has the freedom to opt out and opt back into the EE category annually. If a customer opts out of either the DSM or EE program categories for any year included in the save-a-watt pilot, the customer will never be required to pay any of the non-residential rider rates associated with that category and vintage year. If a customer does not opt out of (or opts back into) one of the program categories for a particular year and actually participates in a program during that year, the customer will be required to pay all of the rates associated with that program category and year, even if the customer opts out of the category for a subsequent year. However, if the customer does not actually participate in a program during a year it has not opted out of (or opted back into) and then opts out of the category for a subsequent year, the customer does not have to pay any rider rates during a time period after it has opted out, even if those rates are associated with the year for which it was not opted out. Consequently, customer participation in Duke's DSM and EE programs, and the corresponding responsibility to pay Rider EE, are determined on an annual basis.

[39] This rate applied to all North Carolina retail non-residential customers served during the rate period January 1, 2011, through December 31, 2011, who participated in a DSM or EE program during Vintage Year 1.

[40] This rate applied to all North Carolina retail non-residential customers served during the rate period January 1, 2011, through December 31, 2011, who did not opt out of the Company's EE programs for Vintage Year 2.

[41] This rate applied to all North Carolina retail non-residential customers served during the rate period January 1, 2011, through December 31, 2011, who did not opt out of the Company's DSM programs for Vintage Year 2.

[42] Docket No. E-7, Sub 938.

3. Duke's Third DSM/EE Cost Recovery and Incentives Proceeding[43]

On March 23, 2011, Duke filed its third application for approval of its DSM/EE cost recovery rider. The Public Staff, Carolina Utility Customers Association, Inc. (CUCA), and the Southern Alliance for Clean Energy intervened. Duke and the Public Staff disagreed: (1) regarding the application of evaluation, measurement, and verification (EM&V) analyses to Duke's EE/DSM program results; and (2) whether avoided costs related to the Home Energy Comparison Report (HECR) Pilot Program[44] should be allocated to customers in both North and South Carolina, and consequently included in Duke's rider for recovery from North Carolina ratepayers.

The Commission held an evidentiary hearing on June 23, 2011, and issued its decision November 8, 2011. The Commission ordered that Duke exclude the costs related to the HECR Pilot Program from the rider. The Order required Duke to file the actual and expected dates when the results of EM&V would become effective for each of its programs. The Order also required Duke to include its EM&V schedule, along with explanations for changes or delays, in its next rider proceeding. In addition, the Commission required Duke to explain in future rider applications how it had applied the results of its EM&V, including the date it begins using the results, the programs to which the results are applied, and the analysis of the cost to perform additional EM&V.

During the rate period January 1, 2012, through December 31, 2012, the rider charges (including gross receipts taxes and regulatory fee) were as follows:

Residential	0.2329 cents/kWh
Non-Residential[45]	
Non-Residential, EE, Vintage Year 1	0.0218 cents/kWh
Non-Residential, DSM Vintage Year 1	0.0205 cents/kwh
Non-Residential, EE/DSM, Vintage Year 2	0.0037 cents/kWh
Non-Residential, EE, Vintage Year 3	0.0406 cents/kWh
Non-Residential, DSM, Vintage Year 3	0.0526 cents/kWh

4. Duke's Fourth DSM/EE Cost Recovery and Incentives Proceeding[46]

On March 23, 2012, Duke filed its fourth application for approval of its DSM/EE cost recovery rider. Southern Alliance for Clean Energy, North Carolina Sustainable Energy Association (NCSEA) and the Public Staff intervened. The Commission held its evidentiary hearing on June 19, 2012. In its post-hearing brief, NCSEA requested that the Commission direct Duke to conduct an analysis of changes in electricity use by

[43] Docket No. E-7, Sub 979.
[44] Duke's HECR pilot program had been approved by the South Carolina Public Service Commission, but Duke had not sought approval of the pilot in North Carolina.
[45] Each rate listed under "non-residential" applies to non-residential customers that are not eligible to opt out and to eligible customers that have not chosen to opt out. If a non-residential customer has opted out of a vintage(s), then the applicable EE and/or DSM charge(s) will not apply to their bill.
[46] Docket No. E-7, Sub 1001.

those large commercial and industrial customers that have opted out of the Company's DSM and EE programs and compile a report containing the results of that analysis.

In its Order issued on September 7, 2012, the Commission rejected NCSEA's proposal, finding that,

> ... although an analysis of aggregate opt-out customer usage data would provide information regarding trends in load, that without an understanding of what is driving those trends such aggregate information would not provide any value. Moreover, the Commission is of the opinion that many factors other than DSM/EE efforts, such as an economic downturn, an economic expansion, or extreme weather would likely explain most of the trends identified by such a study.

The Order also noted Duke's commitment to offer EE and DSM programs attractive to commercial and industrial customers.

The Commission's Order also required Duke to work with the Public Staff and SACE to improve the reporting of its DSM and EE accomplishments and review its EE forecasts using actual participation data to project the impact of existing programs in future DSM/EE rider proceedings.

During the rate period January 1, 2013, through December 31, 2013, the rider charges (including gross receipts taxes and regulatory fee) are as follows:

Residential	0.1638 cents/kWh
Non-Residential[47]	
Non-Residential, EE, Vintage Year 1	0.0155 cents/kWh
Non-Residential, DSM Vintage Year 1	-0.0013 cents/kwh
Non-Residential, EE, Vintage Year 2	0.0488 cents/kWh
Non-Residential, DSM, Vintage Year 2	0.0142 cents/kWh
Non-Residential, EE, Vintage Year 3	0.0053 cents/kWh
Non-Residential, EE, Vintage Year 4	0.0744 cents/kWh
Non-Residential, DSM, Vintage Year 4	0.0594 cents/kWh

5. Duke's Fifth DSM/EE Rider Proceeding and Application for New Incentive Mechanism[48]

On March 6, 2013, Duke filed an application for approval of a new DSM and EE cost recovery and incentive mechanism, as well as a portfolio of new and existing DSM and EE programs.

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[47] Each rate listed under "non-residential" applies to non-residential customers that are not eligible to opt out and to eligible customers that have not chosen to opt out. If a non-residential customer has opted out of a vintage(s), then the applicable EE and/or DSM charge(s) will not apply to their bill.
[48] Docket Nos. E-7, Subs 1031 and 1032.

Duke's proposed cost recovery mechanism would allow Duke to recover:
(1) all reasonable and prudent costs incurred for the adoption and implementation of new DSM/EE programs;
(2) net lost revenues associated with a particular vintage of EE programs for a maximum of three years or the life of the measure; and
(3) a performance incentive with different earning tiers ranging from 0% to 15% after-tax return on program costs.

The incentive earning tiers would be based on the overall cost-effectiveness of the Company's DSM and EE portfolio. The portfolio's cost-effectiveness would be determined by applying the Utility Cost Test (UCT). The UCT score for the portfolio would be calculated at the end of the year by dividing the net present value of Duke's avoided costs achieved by actual program costs, not including EM&V costs. The UCT score would be used to determine the percentage of after-tax return up to a maximum of 15%. That percentage would be multiplied by the program costs to determine Duke's incentive.

The Company proposed to continue several practices previously approved by the Commission for the save-a-watt (SAW) pilot. These include the recovery of NLR; procedures for large customers to opt in and out of participation; applicability of EM&V results; determination of found revenues; program flexibility guidelines; and the stakeholder collaborative. In addition, Duke planned to convene a collaborative to consider the effect that increased participant incentives would have on opt-outs, cost-effectiveness and free ridership. Further, Duke requested the addition of a one week opt-in period to take place each March for customers who had previously elected to opt out during the annual November/December enrollment period.

Similar to the SAW approach, the proposed recovery mechanism would use a vintage year concept, and the Company planned four calendar year vintages during the new program.

A projection of the program costs and the MW and MWh savings that Duke expected to achieve is summarized as follows:

Duke Energy Carolinas System (NC & SC) EE/DSM Portfolio
Projected Results

	2014	2015	2016	2017
Annual System MW	888	970	1,012	1,049
Annual System Net MWh	396,906	408,673	421,892	428,871
Annual Program Costs (Millions)	$101	$105	$107	$111

The Company's proposed rider charge for the new portfolio for January 1, 2014, through December 31, 2014, is 0.3032 cents per kWh for residential customers. For non-residential customers, the amounts differ depending upon customer participation elections. Duke requested approval of Rider 5, to become effective January 1, 2014, which includes amounts related to all four vintages of the SAW pilot and year one of the new portfolio of DSM/EE programs calculated pursuant to its proposed new cost recovery mechanism.

The following organizations intervened in Duke's DSM/EE rider mechanism proceeding:

Carolina Utility Customers Association, Inc. (CUCA)
Environmental Defense Fund (EDF)
North Carolina Sustainable Energy Association (NCSEA)
North Carolina Waste Reduction Network (NC WARN)
Piedmont Natural Gas Co.
Public Service Company of North Carolina, Inc.
Public Staff
Southern Alliance for Clean Energy (SACE)

On August 19, 2013, Duke, EDF, Natural Resources Defense Council, NCSEA, the Public Staff, South Carolina Coastal Conservation League and SACE filed an agreement and stipulation of settlement. That settlement included the following provisions:

1. Approval of all the DSM/EE programs proposed by Duke. However, there would be no four-year sunset on the programs.
2. Duke would be entitled to recover all prudent and reasonable program costs.
3. Duke's incentive payments would be similar to the Progress and Dominion shared savings mechanisms. Duke would receive a program performance incentive (PPI) of 11.5% of the net savings achieved by its DSM and EE programs. In comparison, Progress's PPI percentages are 13% of EE savings and 8% of DSM savings.
4. In addition to the PPI, Duke would receive a $400,000 bonus for each year during 2014-2018 in which it achieved incremental energy savings of 1% of its prior year's system retail sales.
5. The terms of the incentive mechanism would be reviewed by the Commission every four years.
6. Duke would recover net lost revenues on terms essentially as now provided under SAW.
7. The terms of the current Flexibility Guidelines and EM&V Agreement would continue in effect.
8. DEC would continue holding quarterly stakeholder collaborative meetings.

On August 20, 2013, the Commission held its evidentiary hearing in this matter, which remains pending.

DSM/EE Rider Proceedings for Duke Energy Progress, Inc.

1. Progress's First DSM/EE Cost Recovery and Incentives Proceeding

On June 6, 2008, Progress filed an application for approval of an annual DSM and EE cost recovery rider, its first such request under G.S. 62-133.9.[49] Progress initially requested an annual revenue increase of $42.6 million, effective December 1, 2008. Progress reduced its overall request to $41.6 million on August 20, 2008. Progress's request was for costs and utility incentives relative to six programs:

1) Compact Fluorescent Light Pilot
2) Residential Home Advantage
3) Commercial, Industrial, and Governmental New Construction
4) Commercial, Industrial, and Governmental Retrofit (subsequently merged with the new construction program)
5) Distribution System Demand Response (DSDR)
6) Residential EnergyWise™

Of the $41.6 million that Progress requested, $1 million was for a net lost revenue incentive and $6 million was for a shared savings incentive. The shared savings incentive would have been recovered from customers over 10 years and would have equaled 50% of the net present value of savings achieved over the lifetime of a measure, using the "utility cost test" method to calculate a program's net benefits.

On November 14, 2008, the Commission approved Progress's request to put its proposed rider into effect effective December 1, 2008, subject to refund with interest pending the final resolution of the proceeding. Also on November 14, 2008, Progress revised its request by proposing to capitalize its DSM and EE costs, as well as incentives, over 10 years as allowed by G.S. 62-133.9(d)(1), while earning a carrying charge on the unrecovered amounts pursuant to Commission Rule R8-69(b)(6). This reduced Progress's rider request from $41.6 million to $14.8 million by deferring costs into future years.

The following organizations intervened in Progress's DSM/EE rider proceeding:

Attorney General
Carolina Industrial Group for Fair Utility Rates II (CIGFUR II)
Carolina Utility Customers Association, Inc. (CUCA)
Environmental Defense Fund
Natural Resources Defense Council
NC Waste Awareness and Reduction Network
North Carolina Sustainable Energy Association (NCSEA)
Public Staff
Southern Alliance for Clean Energy

[49] Docket No. E-2, Sub 931.

Southern Environmental Law Center
Wal-Mart Stores East, LP and Sam's East, Inc. (Wal-Mart)

On December 9, 2008, Progress, the Public Staff and Wal-Mart filed an agreement and stipulation of partial settlement (Settlement) that addressed most, but not all, of the issues among the three parties. Among the more important issues addressed, the Settlement:

1) Implicitly set the annual revenue requirement for the year ending November 30, 2009, at $10.4 million, down from $14.8 million in Progress's revised request.
2) Set requirements for screening and selecting new DSM and EE programs.
3) Allowed for recovery of costs related to new DSM and EE programs over 10 years with a carrying charge.
4) Allowed Progress to collect from customers two financial incentives for pursuing DSM and EE: three years' worth of net lost revenues, and a "program performance incentive."
5) Would be subject to review and potential modification at least every three years.

On January 7 and 8, 2009, the Commission held an evidentiary hearing and took testimony from expert witnesses. The NCSEA, the Environmental Intervenors[50] and the Attorney General argued that the Settlement should have provided for performance targets that had to be met before Progress could earn an incentive. The Environmental Intervenors also argued that Progress's incentives under the Settlement were unreasonable because they were not commensurate with the Company's risk.

With regard to one unsettled issue, the Public Staff disagreed with Progress's approach to allocating DSM and EE costs among customer classes. Progress and the Public Staff disagreed as to how to interpret G.S. 62-133.9(e), which states as follows:

> The Commission shall determine the appropriate assignment of costs of new demand-side management and energy efficiency measures for electric public utilities and shall assign the costs of the programs only to the class or classes of customers that directly benefit from the programs.

The Public Staff argued that the direct benefits of DSM and EE programs are the system benefits of fewer power plants and lower operating costs, and therefore all customer classes should be required to pay for all of Progress's DSM/EE costs based on each customer class's share of system benefits. Progress, on the other hand, argued that the General Assembly intended that the costs of a program or measure are to be recovered from those customer classes that are eligible to participate in the program.

[50] The Environmental Intervenors include the Southern Alliance for Clean Energy, the Environmental Defense Fund, the Natural Resources Defense Council and the Southern Environmental Law Center.

On June 15, 2009, the Commission issued an Order approving the Settlement with modifications. The Commission disallowed recovery of incentives for Progress's compact fluorescent light pilot and required Progress to amortize and recover its DSM/EE related administrative and general costs over three years, rather than over ten years. The Commission ordered that DSDR costs be recovered from all retail customers that benefit from DSDR, that is, all retail customers that receive power via Progress's distribution system, regardless of the "opt out" provision for industrial and large commercial customers in G.S. 62-133.9(f). The Order required the Public Staff to monitor and review Progress's incremental administrative and general costs on an ongoing basis, with particular emphasis on the effectiveness of the Company's EE education programs, and report its findings to the Commission during Progress's future DSM/EE rider proceedings. The Commission agreed with Progress that the General Assembly intended program costs to be recovered from the specific class(es) of customers eligible to participate in a given program. Finally, unless requested to do so earlier, the Commission would initiate a formal review of Progress's rider and incentive mechanisms no later than June 1, 2012.

On July 13, 2009, Progress filed a motion for reconsideration regarding the Commission's June 15, 2009 Order. Progress requested that the Commission reconsider its decisions relative to:

1) requiring industrial and large commercial customers to pay a portion of its DSDR program costs;
2) allocating DSDR costs between North and South Carolina based on demand; and
3) reporting requirements.

Motions for reconsideration were also filed by CUCA, Wal-Mart and CIGFUR II. On July 20, 2009, the Commission requested comments and reply comments from parties regarding the motions. On August 24, 2009, the Commission scheduled the motions for reconsideration for oral argument on September 16, 2009. As discussed below, the Commission issued an Order ruling on the motions for reconsideration on November 25, 2009.

2. Progress's Second DSM/EE Cost Recovery and Incentives Proceeding

On June 4, 2009, Progress filed its second annual application for approval of a DSM/EE rider.[51] The Commission scheduled this request for public hearing September 16, 2009. Progress requested recovery of $24.2 million for costs, carrying charges and utility incentives associated with the following DSM and EE programs:

1. Compact Fluorescent Light Pilot
2. Commercial, Industrial and Governmental Energy Efficiency
3. Residential Home Advantage
4. Residential Home Energy Improvement

[51] Docket No. E-2, Sub 951.

5. Residential Solar Water Heating Pilot
6. Residential Low-Income Neighborhood Energy Saver
7. Distribution System Demand Response (DSDR)
8. Residential EnergyWise™
9. Commercial, Industrial, and Governmental Demand Response Automation

On July 27, 2009, Progress filed its compliance filing relative to the Commission's June 15, 2009 Order in its first rider proceeding, Docket No. E-2, Sub 931. In that compliance filing, Progress proposed to set customer rates as shown in the third column below, labeled "compliance billing rate." The last column, "proposed new rate," shows Progress's proposed second annual DSM/EE rider rates, updated to comply with the Commission's decisions in the Company's first rider proceeding[52].

Rate Class	Initial Billing Rate[1]	Compliance Billing Rate[2]	Proposed New Rate[3]
Residential	0.074 cents/kWh	0.054 cents/kWh	0.060 cents/kWh
General Service	0.047 cents/kWh	0.045 cents/kWh	0.065 cents/kWh
Lighting	0.000 cents/kWh	0.030 cents/kWh	0.063 cents/kWh

[1] DSM/EE rider charges in effect beginning December 1, 2008, subject to refund.
[2] DSM/EE rider charges reflecting the Commission's decisions relative to Progress's first DSM/EE rider request.
[3] DSM/EE rider charges that reflect the Commission's decisions relative to Progress's first DSM/EE rider request, as well as Progress's second annual DSM/EE rider request. Progress proposed that these rates take effect December 1, 2009. These rates included the impact of gross receipts taxes and regulatory fee.

Progress requested that any rate changes from its first DSM/EE rider request be postponed until December 1, 2009, to coincide with changes pursuant to its second DSM/EE rider request, as well as the Commission's decisions regarding the pending requests for reconsideration in the Company's first rider proceeding.

On November 25, 2009, the Commission issued orders: (1) deciding issues relative to the reconsideration requests in Progress's first rider proceeding[53] and (2) requiring Progress to again recalculate its proposed rider based on those decisions. On March 8, 2010, Progress filed the following rates, which would allow the Company to collect $14.6 million during the period from April 1, 2010, through November 30, 2010.

Residential	0.042 cents/kWh
General Service	0.060 cents/kWh
Lighting	0.077 cents/kWh

On March 19, 2010, the Commission approved the rates that Progress had filed. (The rates include gross receipts taxes and regulatory fee.)

[52] Docket No. E-2, Sub 931.
[53] The Commission determined, on reconsideration, that industrial and large commercial customers that opt out of Progress's EE and DSM programs will not be charged, via the rider, for the DSDR program. For more information, see the Commission's November 25, 2009 Order in Docket No. E-2, Subs 926 and 931.

3. Progress's Third DSM/EE Cost Recovery and Incentives Proceeding

On June 4, 2010, Progress Energy requested its third annual DSM/EE rider.[54] The Company sought to recover its costs, carrying charges and incentives relative to the following programs:

1. Distribution System Demand Response (DSDR)
2. EnergyWise™
3. Commercial, Industrial, and Governmental Demand Response Automation
4. Residential Home Advantage
5. Residential Home Energy Improvement
6. Residential Low-Income Neighborhood Energy Saver
7. Commercial, Industrial, and Governmental Energy Efficiency
8. Residential Lighting
9. Residential Appliance Recycling
10. Residential Solar Water Heater Pilot
11. Compact Fluorescent Light Pilot

The Attorney General and the NCSEA intervened. The Commission held an evidentiary hearing on September 22, 2010. The Public Staff advocated for some minor cost adjustments, which Progress did not oppose. On November 17, 2010, the Commission issued an Order approving a DSM/EE rider via which Progress could recover $59.2 million, subject to true up in its next DSM/EE rider proceeding. Rider charges were set as follows, effective December 1, 2010, excluding gross receipts taxes and regulatory fee:

Residential	0.191 cents/kWh
General Service	0.122 cents/kWh
Lighting	0.066 center/kWh

4. Progress's Fourth DSM/EE Cost Recovery and Incentives Proceeding

On June 3, 2011, Progress requested its fourth annual DSM/EE rider.[55] Progress sought to recover DSM/EE program costs, incentives and carrying charges relative to the following programs:

1. Distribution System Demand Response (DSDR)
2. EnergyWise™
3. Commercial, Industrial, and Governmental Demand Response Automation
4. Residential Home Advantage
5. Residential Home Energy Improvement
6. Residential Low-Income Neighborhood Energy Saver
7. Commercial, Industrial, and Governmental Energy Efficiency
8. Residential Lighting

[54] Docket No. E-2, Sub 977.
[55] Docket No. E-2, Sub 1002.

9. Residential Appliance Recycling
10. Residential Solar Water Heater Pilot
11. Compact Fluorescent Light Pilot
12. Energy Efficiency Benchmarking
13. Home Depot Compact Fluorescent Lighting

CUCA intervened in this proceeding, and the Commission held its evidentiary hearing on September 27, 2011. On November 14, 2011, the Commission approved recovery of $102.3 million via the following rider charges, including gross receipts taxes and regulatory fee:

Residential	0.306 cents/kWh
General Service	0.192 cents/kWh
Lighting	0.088 cents/kWh

The Commission's Order found that it would be appropriate for the Public Staff to initiate a formal review of Progress's DSM/EE rider and incentive mechanism not later than June 1, 2012, and stated that such review should specifically address whether the incentives in the Commission-approved mechanism are producing significant DSM and EE results. In addition, the Commission stated that the review should discuss whether the customer rate impacts from the DSM/EE rider are reasonable and appropriate, and whether overall portfolio targets should be adopted.

On April 10, 2012, the Public Staff filed a motion to extend the time to initiate the formal review of Progress's DSM/EE rider and incentive mechanism. The Public Staff stated that the review of the cost recovery mechanisms for Duke and Dominion are scheduled to occur in 2014, and contended that to postpone the review of Progress's mechanism until 2014 would provide the Commission and the parties with a better context in which to focus on issues identified in that review process. On May 15, 2012, the Commission granted the Public Staff's motion.

5. Progress's Fifth DSM/EE Cost Recovery and Incentives Proceeding[56]

On June 4, 2012, Progress filed its fifth DSM/EE rider application in which it sought cost recovery and incentives for the following programs: .

1. Distribution System Demand Response (DSDR)
2. EnergyWise^{TM}
3. Commercial, Industrial, and Governmental Demand Response Automation
4. Residential Home Advantage
5. Residential Home Energy Improvement
6. Residential Low-Income Neighborhood Energy Saver
7. Commercial, Industrial, and Governmental Energy Efficiency
8. Residential Lighting
9. Residential Energy Efficiency Benchmarking

[56] Docket No. E-2, Sub 1019.

10. Residential Appliance Recycling
11. Residential Solar Water Heater Pilot
12. Compact Fluorescent Light Pilot
13. Small Business Energy Saver
14. Residential New Construction

NCSEA, CUCA, SACE and the Public Staff intervened. The Commission held its evidentiary hearing on September 18, 2012.

On November 27, 2012, the Commission issued its Order approving recovery of $89,290,399 via the following rider charges, including gross receipts taxes and regulatory fee:

Residential	0.365 cents/kWh
General Service	0.337 cents/kWh
Lighting	0.114 cents/kWh

The Order noted that customers responsible for more than half of Progress's commercial and industrial demand had opted out of Progress's DSM/EE programs as allowed by G.S. 62-133.9(f). NCSEA requested that the Commission direct Progress to conduct an analysis in changes or trends in electricity use by those large commercial and industrial customers who have opted-out of the Company's DSM/EE measures and compile a special report containing the results of such analysis. The Commission rejected NCSEA's proposal because there are many factors that can impact the trends in electric use by large commercial and industrial customers, including economic downturn or expansion, the demand for a particular product, or the obsolescence of a product. In addition, Progress was currently investigating sector-based marketing in order to customize the Company's approach to customers that have opted out in order to attract them to the Company's portfolio of DSM and EE programs. The Company had asserted that the cost of its DSDR program caused its DSM/EE rider to be relatively large and that this caused many large commercial and industrial customers to opt-out of participation in Progress's DSM/EE programs. (In Progress's general rate case,[57] the Company initially proposed to move some, but not all, DSDR costs into base rates. That proposal was opposed by some intervenors, and the Company subsequently withdrew it.) The Commission encouraged Progress and the Public Staff to review a representative sample of the Company's opt-out customers to gain a better understanding of their electricity use, to verify what DSM/EE measures they have implemented and to ascertain whether such measures could be expected to reduce the upward usage trend that had been noted by NCSEA.

The Commission's Order also found that Progress and the Public Staff should continue to investigate and provide an update to the Commission within 30 days regarding the feasibility and cost of conducting a market survey regarding the cost effectiveness of Progress's general education programs. On January 18, 2013,

[57] Docket No. E-2, Sub 1023, filed on October 12, 2012, and decided via Commission Order dated May 30, 2013.

Progress and the Public Staff filed a joint recommendation for a market study to assess the effectiveness of Progress's general education and awareness activities. The proposed research plan included survey projects that would cost $49,000 and would require approximately six weeks to complete. SACE filed a letter expressing support for the market study. The Commission subsequently approved the recommendation on March 5, 2013. On May 24, 2013, Progress filed its final report regarding the effectiveness of it general education and awareness activities. That report is available on the Commission's website under Docket No. E-2, Sub 1019.

6. Progress's Sixth DSM/EE Cost Recovery and Incentives Proceeding

On June 12, 2013, Progress filed its sixth DSM/EE rider application[58] in which it seeks recovery of $74.7 million for its DSM and EE programs and related incentives. If approved, Progress's DSM/EE rider would be as follows, including gross receipts tax and regulatory fee:

Residential	0.305 cents/kWh
General Service	0.281 cents/kWh
Lighting	0.108 cents/kWh

Progress seeks recovery of costs related to the following programs:

1. Distribution System Demand Response (DSDR)
2. EnergyWise™
3. Commercial, Industrial, and Governmental Demand Response Automation
4. Residential Home Advantage
5. Residential Home Energy Improvement
6. Residential Low-Income Neighborhood Energy Saver
7. Commercial, Industrial, and Governmental Energy Efficiency
8. Residential Lighting
9. Residential Energy Efficiency Benchmarking
10. Residential Appliance Recycling
11. Residential Solar Water Heater Pilot
12. Small Business Energy Saver
13. Residential New Construction

NCSEA and CUCA have intervened in the proceeding, and the Commission has scheduled the evidentiary hearing for September 17, 2013.

[58] Docket No. E-2, Sub 1030.

APPENDIX A

Rule R8-60. INTEGRATED RESOURCE PLANNING AND FILINGS.

(a) Purpose. — The purpose of this rule is to implement the provisions of G.S. 62-2(3a) and G.S. 62-110.1 with respect to least cost integrated resource planning by the utilities in North Carolina.

(b) Applicability. — This rule is applicable to Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; Duke Energy Carolinas, LLC; Virginia Electric and Power Company, d/b/a Dominion North Carolina Power; the North Carolina Electric Membership Corporation; and any individual electric membership corporation to the extent that it is responsible for procurement of any or all of its individual power supply resources.

(c) Integrated Resource Plan. — Each utility shall develop and keep current an integrated resource plan, which incorporates, at a minimum, the following:

(1) a 15-year forecast of native load requirements (including any off-system obligations approved for native load treatment by the Commission) and other system capacity or firm energy obligations extending through at least one summer or winter peak (other system obligations); supply-side (including owned/leased generation capacity and firm purchased power arrangements) and demand-side resources expected to satisfy those loads; and the reserve margin thus produced; and

(2) a comprehensive analysis of all resource options (supply- and demand-side) considered by the utility for satisfaction of native load requirements and other system obligations over the planning period, including those resources chosen by the utility to provide reliable electric utility service at least cost over the planning period.

Each utility shall include an assessment of demand‑side management and energy efficiency in its integrated resource plan. G.S. 62-133.9(c). In addition, each utility's consideration of supply-side and demand-side resources, including alternative supply-side energy resources, and the provision of reliable electric utility service at least cost shall appropriately consider and incorporate the utility's obligation to comply with the Renewable Energy and Energy Efficiency Portfolio Standard (REPS). G.S. 62-133.8.

(d) Purchased Power. — As part of its integrated resource planning process, each utility shall assess on an on-going basis the potential benefits of soliciting proposals from wholesale power suppliers and power marketers to supply it with needed capacity.

(e) Alternative Supply-Side Energy Resources. — As part of its integrated resource planning process, each utility shall assess on an on-going basis the potential benefits of reasonably available alternative supply-side energy resource options. Alternative supply-side energy resources include, but are not limited to, hydro, wind, geothermal, solar thermal, solar photovoltaic, municipal solid waste, fuel cells, and biomass.

(f) Demand-Side Management. — As part of its integrated resource planning process, each utility shall assess on an on-going basis programs to promote demand-side management, including costs, benefits, risks, uncertainties, reliability and customer acceptance, where appropriate. For purposes of this rule, demand-side management consists of demand response programs and energy efficiency and conservation programs.

(g) Evaluation of Resource Options. — As part of its integrated resource planning process, each utility shall consider and compare a comprehensive set of potential resource options, including both demand-side and supply-side options, to determine an integrated resource plan that offers the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of its system. The utility shall analyze potential resource options and combinations of resource options to serve its system needs, taking into account the sensitivity of its analysis to variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction/implementation costs, transmission and distribution costs, and costs of complying with environmental regulation. Additionally, the utility's analysis should take into account, as applicable, system operations, environmental impacts, and other qualitative factors.

(h) Filings.

(1) By September 1, 2008, and every two years thereafter, each utility subject to this rule shall file with the Commission its then current integrated resource plan, together with all information required by subsection (i) of this rule. This biennial report shall cover the next succeeding two-year period.

(2) By September 1 of each year in which a biennial report is not required to be filed, an annual report shall be filed with the Commission containing an updated 15-year forecast of the items described in subparagraph (c)(1), as well as significant amendments or revisions to the most recently filed biennial report, including amendments or revisions to the type and size of resources identified, as applicable.

(3) Each biennial and annual report filed shall be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports.

(4) Each biennial and annual report shall include the utility's REPS compliance plan pursuant to Rule R8-67(b).

(5) If a utility considers certain information in its biennial or annual report to be proprietary, confidential, and within the scope of G.S. 132-1.2, the utility may designate the information as "confidential" and file it under seal.

(i) Contents of Reports. — Each utility shall include in each biennial report, revised as applicable in each annual report, the following:

(1) Forecasts of Load, Supply-Side Resources, and Demand-Side Resources. — The forecasts filed by each utility as part of its biennial report shall

include descriptions of the methods, models, and assumptions used by the utility to prepare its peak load (MW) and energy sales (MWh) forecasts and the variables used in the models. In both the biennial and annual reports, the forecasts filed by each utility shall include, at a minimum, the following:

(i) The most recent ten-year history and a forecast of customers by each customer class, the most recent ten-year history and a forecast of energy sales (kWh) by each customer class;

(ii) A tabulation of the utility's forecast for at least a 15-year period, including peak loads for summer and winter seasons of each year, annual energy forecasts, reserve margins, and load duration curves, with and without projected supply- or demand-side resource additions. The tabulation shall also indicate the projected effects of demand response and energy efficiency programs and activities on the forecasted annual energy and peak loads on an annual basis for a 15-year period, and these effects also may be reported as an equivalent generation capacity impact; and

(iii) Where future supply-side resources are required, a description of the type of capacity/resource (base, intermediate, or peaking) that the utility proposes to use to address the forecasted need.

(2) Generating Facilities. — Each utility shall provide the following data for its existing and planned electric generating facilities (including planned additions and retirements, but excluding cogeneration and small power production):

(i) Existing Generation. — The utility shall provide a list of existing units in service, with the information specified below for each listed unit. The information shall be provided for a 15-year period beginning with the year of filing:

a. Type of fuel(s) used;

b. Type of unit (e.g., base, intermediate, or peaking);

c. Location of each existing unit;

d. A list of units to be retired from service with location, capacity and expected date of retirement from the system;

e. A list of units for which there are specific plans for life extension, refurbishment or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, general location, capacity rating upon return to service, expected return to service date, and a general description of work to be performed; and

f. Other changes to existing generating units that are expected to increase or decrease generation capability of the unit in question by an amount that is plus or minus 10%, or 10 MW, whichever is greater.

(ii) Planned Generation Additions. — Each utility shall provide a list of planned generation additions, the rationale as to why each listed generation addition was selected, and a 15-year projection of the following for each listed addition:

a. Type of fuel(s) used;

b. Type of unit (e.g. baseload, intermediate, peaking);

c. Location of each planned unit to the extent such location has been determined; and

d. Summaries of the analyses supporting any new generation additions included in its 15-year forecast, including its designation as base, intermediate, or peaking capacity.

(iii) Non-Utility Generation. — Each utility shall provide a separate and updated list of all non-utility electric generating facilities in its service areas, including customer-owned and stand-by generating facilities. This list shall include the facility name, location, primary fuel type, and capacity (including its designation as base, intermediate, or peaking capacity). The utility shall also indicate which facilities are included in its total supply of resources. If any of this information is readily accessible in documents already filed with the Commission, the utility may incorporate by reference the document or documents in its report, so long as the utility provides the docket number and the date of filing.

(3) Reserve Margins. — The utility shall provide a calculation and analysis of its winter and summer peak reserve margins over the projected 15-year period. To the extent the margins produced in a given year differ from target reserve margins by plus or minus 3%, the utility shall explain the reasons for the difference.

(4) Wholesale Contracts for the Purchase and Sale of Power.

(i) The utility shall provide a list of firm wholesale purchased power contracts reflected in the biennial report, including the primary fuel type, capacity (including its designation as base, intermediate, or peaking capacity), location, expiration date, and volume of purchases actually made since the last biennial report for each contract.

(ii) The utility shall discuss the results of any Request for Proposals (RFP) for purchased power it has issued since its last biennial report. This discussion shall include a description of each RFP, the number of entities responding to the RFP, the number of proposals received, the terms of the proposals, and an explanation of why the proposals were accepted or rejected.

(iii) The utility shall include a list of the wholesale power sales contracts for the sale of capacity or firm energy for which the utility has committed to sell power during the planning horizon, the identity of each wholesale entity to which the utility has committed itself to sell power during the planning horizon, the number of megawatts (MW) on an annual basis for each contract, the length of each contract, and the type of each contract (e.g., native load priority, firm, etc.).

(5) Transmission Facilities. — Each utility shall include a list of transmission lines and other associated facilities (161 kV or over) which are under construction or for which there are specific plans to be constructed during the planning horizon, including the capacity and voltage levels, location, and schedules for completion and operation. The utility shall also include a discussion of the adequacy of its transmission system (161 kV and above).

(6) Demand-Side Management. — Each utility shall provide the results of its overall assessment of existing and potential demand-side management programs, including a descriptive summary of each analysis performed or used by the utility in the assessment. The utility also shall provide general information on any changes to the methods and assumptions used in the assessment since its last biennial report.

(i) For demand-side programs available at the time of the report, the utility shall provide the following information for each resource: the type of resource (demand response or energy efficiency); the capacity and energy available in the program; number of customers enrolled in each program; the number of times the utility has called upon the resource; and, where applicable, the capacity reduction realized each time since the previous biennial report. The utility shall also list any demand-side resource it has discontinued since its previous biennial report and the reasons for that discontinuance.

(ii) For demand-side management programs it proposes to implement within the biennium for which the report is filed, the utility shall provide the following information for each resource: the type of resource (demand response and energy efficiency); a description of the new program and the target customer segment; the capacity and energy expected to be available from the program; projected customer acceptance; the date the program will be launched; and the rationale as to why the program was selected.

(iii) For programs evaluated but rejected the utility shall provide the following information for each resource considered: the type of resource (demand response or energy efficiency); a description of the program and the target customer segment; the capacity and energy available from the program; projected customer acceptance; and reasons for the program's rejection.

(iv) For consumer education programs the utility shall provide a comprehensive list of all such programs the utility currently provides to its customers, or proposes to implement within the biennium for which the report is filed, including a description of the program, the target customer segment, and the utility's promotion of the education program. The utility shall also provide a list of any educational program it has discontinued since its last biennial report and the reasons for discontinuance.

(7) Assessment of Alternative Supply-Side Energy Resources. — The utility shall include its current overall assessment of existing and potential alternative supply-side energy resources, including a descriptive summary of

each analysis performed or used by the utility in the assessment. The utility shall also provide general information on any changes to the methods and assumptions used in the assessment since its most recent biennial or annual report.

(i) For the currently operational or potential future alternative supply-side energy resources included in each utility's plan, the utility shall provide information on the capacity and energy actually available or projected to be available, as applicable, from the resource. The utility shall also provide this information for any actual or potential alternative supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance.

(ii) For alternative supply-side energy resources evaluated but rejected, the utility shall provide the following information for each resource considered: a description of the resource; the potential capacity and energy associated with the resource; and the reasons for the rejection of the resource.

(8) Evaluation of Resource Options. — Each utility shall provide a description and a summary of the results of its analyses of potential resource options and combinations of resource options performed by it pursuant to subsection (g) of this rule to determine its integrated resource plan.

(9) Levelized Busbar Costs. — Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; Duke Energy Carolinas, LLC; and Virginia Electric and Power Company, d/b/a Dominion North Carolina Power shall provide information on levelized busbar costs for various generation technologies.

(j) Review. — Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report of amendments or revisions, the Public Staff or any other intervenor may file an integrated resource plan or report of its own as to any utility or may file an evaluation of or comments on the reports filed by the utilities, or both. The Public Staff or any intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. Within 14 days after the filing of initial comments, the parties may file reply comments addressing any substantive or procedural issue raised by any other party. A hearing to address issues raised by the Public Staff or other intervenors may be scheduled at the discretion of the Commission. The scope of any such hearing shall be limited to such issues as identified by the Commission. One or more hearings to receive testimony from the public, as required by law, shall be set at a time and place designated by the Commission.

(NCUC Docket No. E 100, Sub 54, 12/8/88; NCUC Docket No. E-100, Sub 78A, 04/29/98; 08/11/98; NCUC Docket No. M-100, Sub 128, 10/27/99; NCUC Docket No. E-100, Sub 113, 2/29/08; NCUC Docket No. E-100, Sub 113, 3/13/08.)

R8-67 RENEWABLE ENERGY AND ENERGY EFFICIENCY PORTFOLIO STANDARD (REPS)

(a) Definitions.

(1) The following terms shall be defined as provided in G.S. 62-133.8: “Combined heat and power system”; “demand-side management”; “electric power supplier”; “new renewable energy facility”; “renewable energy certificate”; “renewable energy facility”; “renewable energy resource”; and “incremental costs.”

(2) For purposes of determining an electric power supplier’s avoided costs, “avoided cost rates” mean an electric power supplier’s most recently approved or established avoided cost rates in this state, as of the date the contract is executed, for purchases of electricity from qualifying facilities pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978. If the Commission has approved an avoided cost rate for the electric power supplier for the year when the contract is executed, applicable to contracts of the same nature and duration as the contract between the electric power supplier and the seller, that rate shall be used as the avoided cost. Therefore, for example, for a contract by an electric public utility with a term of 15 years, the avoided cost rate applicable to that contract would be the comparable, Commission-approved, 15-year, long-term, levelized rate in effect at the time the contract was executed. In all other cases, the avoided cost shall be a good faith estimate of the electric power supplier’s avoided cost, levelized over the duration of the contract, determined as of the date the contract is executed, taking into consideration the avoided cost rates then in effect as established by the Commission. In any event, when found by the Commission to be appropriate and in the public interest, a good faith estimate of an electric public utility’s avoided cost, levelized over the duration of the contract, determined as of the date the contract is executed, may be used in a particular REPS cost recovery proceeding. Determinations of avoided costs, including estimates thereof, shall be subject to continuing Commission oversight and, if necessary, modification should circumstances so require.

(3) “Energy efficiency measure” means an equipment, physical, or program change that when implemented results in less use of energy to perform the same function or provide the same level of service. “Energy efficiency measure” does not include demand-side management. It includes energy produced from a combined heat and power system that uses nonrenewable resources to the extent the system:

(i) Uses waste heat to produce electricity or useful, measurable thermal or mechanical energy at a retail electric customer’s facility; and

(ii) Results in less energy used to perform the same function or provide the same level of service at a retail electric customer’s facility.

(4) “Year-end number of customer accounts” means the number of accounts within each customer class as of December 31 for a given calendar

year determined in a manner approved by the Commission pursuant to subsection (c)(4) or determined in the same manner as that information is reported to the Energy Information Administration, United States Department of Energy, for annual electric sales and revenue reporting.

(5) "Utility compliance aggregator" is an organization that assists an electric power supplier in demonstrating its compliance with REPS. Such demonstration may include, among other things, filing REPS compliance plans or reports and participating in NC-RETS on behalf of the electric power supplier or a group of electric power suppliers.

(b) REPS compliance plan.

(1) Each year, beginning in 2008, each electric power supplier or its designated utility compliance aggregator shall file with the Commission the electric power supplier's plan for complying with G.S. 62-133.8(b), (c), (d), (e) and (f). The plan shall cover the calendar year in which the plan is filed and the immediately subsequent two calendar years. At a minimum, the plan shall include the following information:

(i) a specific description of the electric power supplier's planned actions to comply with G.S. 62-133.8(b), (c), (d), (e) and (f) for each year;

(ii) a list of executed contracts to purchase renewable energy certificates (whether or not bundled with electric power), including type of renewable energy resource, expected MWh, and contract duration;

(iii) a list of those planned or implemented energy efficiency and demand side management measures that the electric power supplier plans to use toward REPS compliance, including a brief description of each measure, its projected impacts, and a measurement and verification plan if such plan has not otherwise been filed with the Commission;

(iv) the projected North Carolina retail sales and year-end number of customer accounts by customer class for each year;

(v) the current and projected avoided cost rates for each year;

(vi) the projected total and incremental costs anticipated to implement the compliance plan for each year;

(vii) a comparison of projected costs to the annual cost caps for each year;

(viii) for electric public utilities, an estimate of the amount of the REPS rider and the impact on the cost of fuel and fuel-related costs rider necessary to fully recover the projected costs; and

(ix) to the extent not already filed with the Commission, the electric power supplier shall, on or before September 1 of each year, file a renewable energy facility registration statement pursuant to Rule R8-66 for any facility it owns and upon which it is relying as a source of power or RECs in its REPS compliance plan.

(2) Each electric power supplier shall file its REPS compliance plan with the Commission on or before September 1 of each year.

(3) Any electric power supplier subject to Rule R8-60 shall file its REPS compliance plan as part of its integrated resource plan filing, and the REPS compliance plan will be reviewed and approved pursuant to Rule R8-60. Approval of the REPS compliance plan as part of the integrated resource plan shall not constitute an approval of the recovery of costs associated with REPS compliance or a determination that the electric power supplier has complied with G.S. 62 133.8(b), (c), (d), (e), and (f).

(4) An REPS compliance plan filed by an electric power supplier not subject to Rule R8-60 shall be for information only.

(c) REPS compliance report.

(1) Each year, beginning in 2009, each electric power supplier or its designated utility compliance aggregator shall file with the Commission a report describing the electric power supplier's compliance with the requirements of G.S. 62-133.8(b), (c), (d), (e) and (f) during the previous calendar year. The report shall include all of the following information, including supporting documentation:

(i) the sources, amounts, and costs of renewable energy certificates, by source, used to comply with G.S. 62-133.8(b), (c), (d), (e) and (f). Renewable energy certificates for energy efficiency may be based on estimates of reduced energy consumption through the implementation of energy efficiency measures, to the extent approved by the Commission;

(ii) the actual North Carolina retail sales and year-end number of customer accounts by customer class;

(iii) the current avoided cost rates and the avoided cost rates applicable to energy received pursuant to long-term power purchase agreements;

(iv) the actual total and incremental costs incurred during the calendar year to comply with G.S. 62-133.8(b), (c), (d), (e) and (f);

(v) a comparison of the actual incremental costs incurred during the calendar year to the per-account annual charges (in G.S. 62-133.8(g)(4)) applied to its total number of customer accounts as of December 31 of the previous calendar year;

(vi) the status of compliance with the requirements of G.S. 62-133.8(b), (c), (d), (e) and (f);

(vii) the identification of any renewable energy certificates or energy savings to be carried forward pursuant to G.S. 62-133.8(b)(2)f or (c)(2)f;

(viii) the dates and amounts of all payments made for renewable energy certificates; and

(ix) for electric membership corporations and municipal electric suppliers, reduced energy consumption achieved in each year after January 1, 2008, through the implementation of energy efficiency or demand-side management programs, along with the results of each program's measurement and verification plan, or other documentation supporting an estimate of the program's energy reductions achieved in the previous year pending implementation of a measurement and verification plan. Supporting documentation shall be retained and made available for audit.

(2) Each electric public utility shall file its annual REPS compliance report , together with direct testimony and exhibits of expert witnesses, on the same date that it files (1) its cost recovery request under Rule R8-67(e), and (2) the information required by Rule R8-55. The Commission shall consider each electric public utility's REPS compliance report at the hearing provided for in subsection (e) of this rule and shall determine whether the electric public utility has complied with G.S. 62-133.8(b), (d), (e) and (f). Public notice and deadlines for intervention and filing of additional direct and rebuttal testimony and exhibits shall be as provided for in subsection (e) of this rule.

(3) Each electric membership corporation and municipal electric supplier or their designated utility compliance aggregator shall file a verified REPS compliance report on or before September 1 of each year. The Commission may issue an order scheduling a hearing to consider the REPS compliance report filed by each electric membership corporation or municipal electric supplier, requiring public notice, and establishing deadlines for intervention and the filing of direct and rebuttal testimony and exhibits.

(4) In each electric power supplier's initial REPS compliance report, the electric power supplier shall propose a methodology for determining its cap on incremental costs incurred to comply with G.S. 62-133.8(b), (c), (d), (e) and (f) and fund research as provided in G.S. 62-133.8(h)(1), including a determination of year-end number of customer accounts. The proposed methodology may be specific to each electric power supplier, shall be based upon a fair and reasonable allocation of costs, and shall be consistent with G.S. 62-133.8(h). The electric power supplier may propose a different methodology that meets the above requirements in a subsequent REPS compliance report filing. For electric public utilities, this methodology shall also be used for assessing the per-account charges pursuant to G.S. 62-133.8(h)(5).

(5) In any year, an electric power supplier or other interested party may petition the Commission to modify or delay the provisions of G.S. 62-133.8(b), (c), (d), (e) and (f), in whole or in part. The Commission may grant such petition upon a finding that it is in the public interest to do so. If an electric power supplier is the petitioner, it shall demonstrate that it has made a reasonable effort to meet the requirements of such provisions. Retroactive modification or delay of the provisions of G.S. 62-133.8(b), (c), (d), (e) or (f) shall not be permitted. The Commission shall allow a modification or delay only with respect to the electric power supplier or group of electric power suppliers for which a need for a modification or delay has been demonstrated.

(6) A group of electric power suppliers may aggregate their REPS obligations and compliance efforts provided that all suppliers in the group are

subject to the same REPS obligations and compliance methods as stated in either G.S. 133.8(b) or (c). If such a group of electric power suppliers fails to meet its REPS obligations, the Commission shall find and conclude that each supplier in the group, individually, has failed to meet its REPS obligations.

(d) Renewable energy certificates.

(1) Renewable energy certificates (whether or not bundled with electric power) claimed by an electric power supplier to comply with G.S. 62-133.8(b), (c), (d), (e) and (f) must have been earned after January 1, 2008; must have been purchased by the electric power supplier within three years of the date they were earned; shall be retired when used for compliance; and shall not be used for any other purpose. A renewable energy certificate may be used to comply with G.S. 62-133.8(b), (c), (d), (e) and (f) in the year in which it is acquired or obtained by an electric power supplier or in any subsequent year; provided, however, that an electric public utility must use a renewable energy certificate to comply with G.S. 62-133.8(b), (d), (e) and (f) within seven years of cost recovery pursuant to subsection (e)(10) of this Rule.

(2) For any facility that uses both renewable energy resources and nonrenewable energy resources to produce energy, the facility shall earn renewable energy certificates based only upon the energy derived from renewable energy resources in proportion to the relative energy content of the fuels used.

(3) Renewable energy certificates earned by a renewable energy facility after the date the facility's registration is revoked by the Commission shall not be used to comply with G.S. 62-133.8(b), (c), (d), (e) and (f).

(4) Renewable energy certificates must be issued by, or imported into, the renewable energy certificate tracking system established in Rule R8-67(h) in order to be eligible RECs under G.S. 62-133.8.

(e) Cost recovery.

(1) For each electric public utility, the Commission shall schedule an annual public hearing pursuant to G.S. 62-133.8(h) to review the costs incurred by the electric public utility to comply with G.S. 62-133.8(b), (d), (e) and (f). The annual rider hearing for each electric public utility will be scheduled as soon as practicable after the hearing held by the Commission for the electric public utility under Rule R8-55.

(2) The Commission shall permit each electric public utility to charge an increment or decrement as a rider to its rates to recover in a timely manner the reasonable incremental costs prudently incurred to comply with G.S. 62-133.8(b), (d), (e) and (f). The cost of an unbundled renewable energy certificate, to the extent that it is reasonable and prudently incurred, is an incremental cost and has no avoided cost component.

(3) Unless otherwise ordered by the Commission, the test period for each electric public utility shall be the same as its test period for purposes of Rule R8-55.

(4) Rates set pursuant to this section shall be recovered during a fixed cost recovery period that shall coincide, to the extent practical, with the recovery period for the cost of fuel and fuel-related cost rider established pursuant to Rule R8-55.

(5) The incremental costs will be further modified through the use of an REPS experience modification factor (REPS EMF) rider. The REPS EMF rider will reflect the difference between reasonable and prudently incurred incremental costs and the revenues that were actually realized during the test period under the REPS rider then in effect. Upon request of the electric public utility, the Commission shall also incorporate in this determination the experienced over-recovery or under-recovery of the incremental costs up to thirty (30) days prior to the date of the hearing, provided that the reasonableness and prudence of these costs shall be subject to review in the utility's next annual REPS cost recovery hearing.

(6) The REPS EMF rider will remain in effect for a fixed 12-month period following establishment and will carry through as a rider to rates established in any intervening general rate case proceedings.

(7) Pursuant to G.S. 62-130(e), any over-collection of reasonable and prudently incurred incremental costs to be refunded to a utility's customers through operation of the REPS EMF rider shall include an amount of interest, at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate.

(8) Each electric public utility shall follow deferred accounting with respect to the difference between actual reasonable and prudently-incurred incremental costs and related revenues realized under rates in effect.

(9) The incremental costs to be recovered by an electric public utility in any cost recovery period from its North Carolina retail customers to comply with G.S. 62-133.8(b), (d), (e), and (f) shall not exceed the per-account charges set forth in G.S. 62-133.8(h)(4) applied to the electric public utility's year-end number of customer accounts determined as of December 31 of the previous calendar year. These annual charges shall be collected through fixed monthly charges. Each electric public utility shall ensure that the incremental costs recovered under the REPS rider and REPS EMF rider during the cost recovery period, inclusive of gross receipts tax and the regulatory fee, from any given customer account do not exceed the applicable per-account charges set forth in G.S. 62-133.8(h)(4).

(10) Incremental costs incurred during a calendar year toward a current or future year's REPS obligation may be recovered by an electric public utility in any 12-month recovery period up to and including the 12-month recovery period in which the RECs associated with any incremental costs are retired toward the prior year's REPS obligation, as long as the electric public utility's charges to customers do not exceed, in any 12-month period, the per-account annual charges provided in G.S. 62-133.8(h)(4). A renewable energy certificate must be used for compliance and retired within seven years of the year in which

the electric public utility recovers the related costs from customers. An electric public utility shall refund to customers with interest the costs for renewable energy certificates that are not used for compliance within seven years.

(11) Each electric public utility, at a minimum, shall submit to the Commission for purposes of investigation and hearing the information required for the REPS compliance report for the 12-month test period established in subsection (3) normalized, as appropriate, consistent with Rule R8-55, accompanied by supporting workpapers and direct testimony and exhibits of expert witnesses, and any change in rates proposed by the electric public utility at the same time that it files the information required by Rule R8-55.

(12) The electric public utility shall publish a notice of the annual hearing for two (2) successive weeks in a newspaper or newspapers having general circulation in its service area, normally beginning at least 30 days prior to the hearing, notifying the public of the hearing before the Commission pursuant to G.S. 62-133.8(h) and setting forth the time and place of the hearing.

(13) Persons having an interest in said hearing may file a petition to intervene setting forth such interest at least 15 days prior to the date of the hearing. Petitions to intervene filed less than 15 days prior to the date of the hearing may be allowed in the discretion of the Commission for good cause shown.

(14) The Public Staff and other intervenors shall file direct testimony and exhibits of expert witnesses at least 15 days prior to the hearing date. If a petition to intervene is filed less than 15 days prior to the hearing date, it shall be accompanied by any direct testimony and exhibits of expert witnesses the intervenor intends to offer at the hearing.

(15) The electric public utility may file rebuttal testimony and exhibits of expert witnesses no later than 5 days prior to the hearing date.

(16) The burden of proof as to whether the costs were reasonable and prudently incurred shall be on the electric public utility.

(f) Contracts with owners of renewable energy facilities.

(1) The terms of any contract entered into between an electric power supplier and a new solar electric facility or new metered solar thermal energy facility shall be of sufficient length to stimulate development of solar energy.

(2) Each electric power supplier shall include appropriate language in all agreements for the purchase of renewable energy certificates (whether or not bundled with electric power) prohibiting the seller from remarketing the renewable energy certificates being purchased by the electric power supplier.

(g) Metering of renewable energy facilities.

(1) Except as provided below, for the purpose of receiving renewable energy certificate issuance in NC-RETS, the electric power generated by a renewable energy facility shall be measured by an electric meter supplied by and read by an electric power supplier. Facilities whose renewable energy certificates

are issued in a tracking system other than NC-RETS shall be subject to the requirements of the applicable state commission and/or tracking system.

(2) The electric power generated by an inverter-based solar photovoltaic (PV) system with a nameplate capacity of 10 kW or less may be estimated using generally accepted analytical tools.

(3) The electric power generated by a renewable energy facility interconnected on the customer's side of the utility meter at a customer's location may be measured by (1) an ANSI-certified electric meter not provided by an electric power supplier provided that the owner of the meter complies with the meter testing requirements of Rule R8-13, or (2) another industry-accepted, auditable and accurate metering, controls, and verification system. The data provided by such meter or system may be read and self-reported by the owner of the renewable energy facility, subject to audit by the Public Staff. The owner of the meter shall retain for audit for 10 years the energy output data.

(4) Thermal energy produced by a combined heat and power system or solar thermal energy facility shall be the thermal energy recovered and used for useful purposes other than electric power production. The useful thermal energy may be measured by meter, or if that is not practicable, by other industry-accepted means that show what measurable amount of useful thermal energy the system or facility is designed and operated to produce and use. Renewable energy certificates shall be earned based on one certificate for every 3,412,000 British thermal units (Btu) of useful thermal energy produced. Meter devices, if used, shall be located so as to measure the actual thermal energy consumed by the load served by the facility. Thermal energy output that is used as station power or to process the facility's fuel is not eligible for RECs. Thermal energy production data, whether metered or estimated, shall be retained for audit for 10 years.

(h) North Carolina Renewable Energy Certificate Tracking System (NC-RETS)

(1) Definitions

(i) "Balancing area operator" means an electric power supplier that has the responsibility to act as the balancing authority for a portion of the regional transmission grid, including maintaining the load-to-generation balance, accounting for energy delivered into and exported out of the area, and supporting interconnection frequency in real time.

(ii) "Multi-fuel facility" means a renewable energy facility that produces energy using more than one fuel type, potentially relying on a fuel that does not qualify for REC issuance in North Carolina.

(iii) "Participant" means a person or organization that opens an account in NC-RETS.

(iv) "Qualifying thermal energy output" is the useful thermal energy: (1) that is made available to an industrial or commercial process (net of any heat contained in condensate return and/or makeup water);

(2) that is used in a heating application (e.g., space heating, domestic hot water heating); or (3) that is used in a space cooling application (i.e., thermal energy used by an absorption chiller).

(2) A renewable energy certificate (REC) tracking system, to be known as NC-RETS, is established by the Commission. NC-RETS shall issue, track, transfer and retire RECs. It shall calculate each electric power supplier's REPS obligation and report each electric power supplier's REPS accomplishments, consistent with the compliance report filed under Rule R8-67(c). NC-RETS shall be administered by a third-party vendor selected by the Commission. Only RECs issued by or imported into NC-RETS are qualifying RECs under G.S. 62-133.8.

(3) Each electric power supplier shall be a participant in NC-RETS and shall provide data to NC-RETS to calculate its REPS obligation and to demonstrate its compliance with G.S. 62-133.8. An electric power supplier may select a utility compliance aggregator to participate in NC-RETS on its behalf and file REPS compliance plans and compliance reports, but the supplier shall nonetheless remain responsible for its own compliance. For reporting purposes, an electric power supplier or its utility compliance aggregator may aggregate the supplier's compliance obligations and accomplishments with those of other suppliers that are subject to the same obligations under G.S. 62-133.8.

(4) Each renewable energy facility or new renewable energy facility registered by the Commission under Rule R8-66 shall participate in NC-RETS in order to have RECs issued, or in another REC tracking system in order to have RECs issued and transferred into NC-RETS, but no facility's meter data for the same time period shall be used for simultaneous REC issuance in two such systems. Beginning June 1, 2011, renewable energy facilities registered in NC-RETS may only enter historic energy production data for REC issuance that goes back up to two years from the current date. Facilities that produce energy using one or more renewable energy resource(s) and another resource that does not qualify toward REPS compliance under G.S. 62-133.8 shall calculate on a monthly basis and provide to NC-RETS the percentage of energy output attributable to each fuel source. NC-RETS will issue RECs only for energy emanating from sources that qualify under G.S. 62-133.8.

(5) Each balancing area operator shall provide monthly electric generation production data to NC-RETS for renewable and new renewable energy facilities that are interconnected to the operator's electric transmission system. Such balancing area operator shall retain documentation verifying the production data for audit by the Public Staff.

(6) Each electric power supplier that has registered renewable energy facilities or new renewable energy facilities interconnected with its electric distribution system and that reads the electric generation production meters for those facilities shall provide monthly the facilities' energy output to NC-RETS, and shall retain for audit for 10 years that energy output data. Municipalities and electric membership corporations may elect to have the facilities' production data reported to NC-RETS and retained for audit by a utility compliance aggregator.

(7) A renewable energy facility or new renewable energy facility that produces thermal energy that qualifies for RECs shall report the facility's qualifying thermal energy output to NC-RETS at least every 12 months. A renewable energy facility or new renewable energy facility that reports its data pursuant to Rule R8-67(g)(3) shall report its energy output to NC-RETS at least every 12 months.

(8) The owner of an inverter-based solar photovoltaic system with a nameplate capacity of 10 kW or less may estimate its energy output using generally accepted analytical tools pursuant to Rule R8-67(g)(2). Such an owner, or its agent, of this kind of facility shall report the facility's energy output to NC-RETS at least every 12 months.

(9) All energy output and fuel data for multi-fuel facilities, including underlying documentation, calculations, and estimates, shall be retained for audit for at least ten years immediately following the provision of the output data to NC-RETS or another tracking system, as appropriate.

(10) Each electric power supplier that complies with G.S. 62-133.8 by implementing energy efficiency or demand-side management programs shall use NC-RETS to report the energy savings of those programs. Municipal power suppliers and electric membership corporations may elect to have their energy savings from their energy efficiency and demand-side management programs reported to NC-RETS by a utility compliance aggregator, and to have their reported savings consolidated with the reported savings from other municipal power suppliers or electric membership corporations if and as necessary to permit aggregate reporting through their utility compliance aggregator. Records regarding which electric power supplier achieved the energy efficiency and demand-side management, the programs that were used, and the year in which it was achieved, shall be retained for audit.

(11) All Commission-approved costs of developing and operating NC-RETS shall be allocated among all electric power suppliers based upon their respective share of the total megawatt-hours of retail electricity sales in North Carolina in the previous calendar year. Each electric power supplier, or its utility compliance aggregator, shall, within 60 days of NC-RETS beginning operations, and by June 1 of each subsequent year, enter its previous year's retail electricity sales into NC-RETS, which sales will be used by NC-RETS to calculate each electric power supplier's REPS obligations and NC-RETS charges. NC-RETS shall update its billings beginning each July based on retail sales data for the previous calendar year. Such NC-RETS charges shall be deemed to be costs that are reasonable, prudent, incremental, and eligible for recovery through each electric public utility's annual rider established pursuant to G.S. 62-133.8(h).

(12) Each account holder in NC-RETS shall pay the NC-RETS administrator for service according to the following fee schedule:

(i) $0.01 for each REC export to an account residing in a different REC tracking system.

(ii) $0.01 for each REC retired for reasons other than compliance with G.S. 62-133.8.

(13) The Commission shall adopt NC-RETS Operating Procedures. The Commission shall establish an NC-RETS Stakeholder Group that shall meet from time to time and which may recommend changes to the NC-RETS Operating Procedures and NC-RETS.

(14) All data retention requirements of this Rule R8-67(h) may be accomplished via retention of electronic documents.

(NCUC Docket No. E-100, Sub 113, 2/29/08; NCUC Docket No. E-100, Sub 113, 3/13/08; NCUC Docket No. E-100, Subs 113 & 121, 1/31/11; NCUC Docket No. E-43, Sub 6, E-100, Sub 113, EC-33, Sub 58, EC-83, Sub 1, 5/14/2012.)

R8-68 INCENTIVE PROGRAMS FOR ELECTRIC PUBLIC UTILITIES AND ELECTRIC MEMBERSHIP CORPORATIONS, INCLUDING ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT PROGRAMS

(a) Purpose. — The purpose of this rule is to establish guidelines for the application of G.S. 62-140(c) and G.S. 62-133.9 to electric public utilities and electric membership corporations that are consistent with the directives of those statutes and consistent with the public policy of this State as set forth in G.S. 62-2.

(b) Definitions.

(1) Unless listed below, the definitions of all terms used in this rule shall be as set forth in Rule R8-67(a), or if not defined therein, then as set forth in G.S. 62-3, G.S. 62-133.8(a) and G.S. 62-133.9(a).

(2) “Consideration” means anything of economic value paid, given, or offered to any person by an electric public utility or electric membership corporation (regardless of the source of the “consideration’’) including, but not limited to: payments to manufacturers, builders, equipment dealers, contractors including HVAC contractors, electricians, plumbers, engineers, architects, and/or homeowners or owners of multiple housing units or commercial establishments; cash rebates or discounts on equipment/appliance sales, leases, or service installation; equipment/ appliances sold below fair market value or below their cost to the electric public utility or electric membership corporation; low interest loans, defined as loans at an interest rate lower than that available to the person to whom the proceeds of the loan are made available; studies on energy usage; model homes; and payment of trade show or advertising costs. Excepted from the definition of “consideration” are favors and promotional activities that are de minimis and nominal in value and that are not directed at influencing fuel choice decisions for specific applications or locations.

(3) “Costs” include, but are not limited to, all capital costs (including cost of capital and depreciation expenses), administrative costs, implementation costs, participation incentives, and operating costs. “Costs” does not include utility incentives.

(4) “Electric public utility” means a person, whether organized under the laws of this State or under the laws of any other state or country, now or hereafter owning or operating in this State equipment or facilities for producing, transporting, distributing, or furnishing electric service to or for the public for consumption. For purposes of this rule, “electric public utility” does not include electric membership corporations.

(5) “Net lost revenues” means the revenue losses, net of marginal costs avoided at the time of the lost kilowatt-hour sale(s), or in the case of purchased power, in the applicable billing period, incurred by the electric public utility as the result of a new demand-side management or energy efficiency measure. Net lost revenues shall also be net of any increases in revenues resulting from any activity by the electric public utility that causes a customer to

increase demand or energy consumption, whether or not that activity has been approved pursuant to this Rule R8-68.

(6) “New demand-side management or energy efficiency measure” means a demand-side management or energy efficiency measure that is adopted and implemented on or after January 1, 2007, including subsequent changes and modifications to any such measure. Cost recovery for “new demand-side management measures” and “new energy efficiency measures” is subject to G.S. 62-133.9.

(7) “Participation incentive” means any consideration associated with a new demand-side management or energy efficiency measure.

(8) “Program” or “measure” means any electric public utility action or planned action that involves the offering of consideration.

(9) “Utility incentives” means incentives as described in G.S. 62-133.9(d)(2)a-c.

(c) Filing for Approval.

(1) Application of Rule.

(i) Prior to an electric public utility or electric membership corporation implementing any measure or program, the purpose or effect of which is to directly or indirectly alter or influence the decision to use the electric public utility’s or electric membership corporation’s service for a particular end use or to directly or indirectly encourage the installation of equipment that uses the electric public utility’s or electric membership corporation’s service, or any new or modified demand-side management or energy efficiency measure, the electric public utility or the electric membership corporation shall obtain Commission approval, regardless of whether the measure or program is offered at the expense of the shareholders, ratepayers, or third-party.

(ii) This requirement shall also apply to measures and programs that are administered, promoted, or funded by the electric public utility’s or electric membership corporation’s subsidiaries, affiliates, or unregulated divisions or businesses if the electric public utility or electric membership corporation has control over the entity offering or is involved in the measure or program and an intent or effect of the measure or program is to adopt, secure, or increase the use of the electric public utility’s public utility services.

(iii) Any application for approval by an electric public utility or electric membership corporation of a measure or program under this rule shall be made in a unique sub-docket of the electric public utility’s or electric membership corporation’s docket number.

(2) Filing Requirements. — Each application for the approval shall include:

(i) Cover Page. — The electric public utility or electric membership corporation shall attach to the front of an application a cover sheet generally describing:

a. the measure or program;

b. the consideration to be offered;

c. the anticipated total cost of the measure or program;

d. the source and amount of funding to be used; and

e. the proposed classes of persons to whom it will be offered.

(ii) Description. — The electric public utility or electric membership corporation shall provide a description of each measure and program, and include the following:

a. the program or measure's objective;

b. the duration of the program or measure;

c. the targeted sector and eligibility requirements;

d. examples of all communication materials to be used with the measure or program and the related cost for each program year;

e. the estimated number of participants;

f. the impact that each measure or program is expected to have on the electric public utility or electric membership corporation, its customer body as a whole, and its participating North Carolina customers; and

g. any other information the electric public utility or electric membership corporation believes is relevant to the application, including information on competition known by the electric public utility or the electric membership corporation.

(iii) Additionally, an electric public utility shall include or describe:

a. the measure's proposed marketing plan, including a description of market barriers and how the electric public utility intends to address them;

b. the total market potential and estimated market growth throughout the duration of the program;

c. the estimated summer and winter peak demand reduction by unit metric and in the aggregate by year;

d. the estimated energy reduction per appropriate unit metric and in the aggregate by year;

e. the estimated lost energy sales per appropriate unit metric and in the aggregate by year; and

f. the estimated load shape impacts.

(iv) Costs and Benefits. — The electric public utility or electric membership corporation shall provide the following information on the costs and benefits of each proposed measure or program: (a) the estimated total and per unit cost and benefit of the measure or program to the electric public utility or electric membership corporation, reported by type of benefit and expenditure (e.g., capital cost expenditures; administrative costs; operating costs; participation incentives, such as rebates and direct payments; and communications costs, and the costs of measurement and verification) and the planned accounting treatment for those costs and benefits; (b) the type, the maximum and minimum amount of participation incentives to be made to any party, and the reason for any participation incentives and other consideration and to whom they will be offered, including schedules listing participation incentives and other consideration to be offered; and (c) service limitations or conditions planned to be imposed on customers who do not participate in the measure. With respect to communications costs, the electric public utility or electric membership corporation shall provide detailed cost information on communications materials related to each proposed measure or program. Such costs shall be included in the Commission's consideration of the total cost of the measure or program and whether the total cost of the measure or program is reasonable in light of the benefits.

(v) Cost-Effectiveness Evaluation. — The electric public utility or electric membership corporation shall provide the economic justification for each proposed measure or program, including the results of all cost-effectiveness tests. Cost-effectiveness evaluations performed by the electric public utility or electric membership corporation should be based on direct or quantifiable costs and benefits and should include, at a minimum, an analysis of the Total Resource Cost Test, the Participant Test, the Utility Cost Test, and the Ratepayer Impact Measure Test. In addition, an electric public utility shall describe the methodology used to produce the impact estimates as well as, if appropriate, methodologies considered and rejected in the interim leading to the final model specification.

(vi) Commission Guidelines Regarding Incentive Programs. — The electric public utility or electric membership corporation shall provide the information necessary to comply with the Commission's Revised Guidelines for Resolution of Issues Regarding Incentive Programs, issued by Commission Order on March 27, 1996, in Docket No. M-100, Sub 124, set out as an Appendix to Chapter 8 of these rules.

(vii) Integrated Resource Plan. — When seeking approval of a new demand-side management or new energy efficiency measure, the electric public utility or electric membership corporation shall explain in detail how the measure is consistent with the electric public utility's or electric membership corporation's integrated resource plan filings pursuant to Rule R8-60.

(viii) Other. — Any other information the electric public utility or electric membership corporation believes relevant to the application, including information on competition known by the electric public utility or the electric membership corporation.

(3) Additional Filing Requirements. — In addition to the information listed in subsection (c)(2), an electric public utility filing for approval of a new or modified demand-side management or energy efficiency measure shall provide the following:

(i) Costs and Benefits. – The electric public utility shall describe:

a. any costs incurred or expected to be incurred in adopting and implementing a measure or program to be considered for recovery through the annual rider under G.S. 62-133.9;

b. estimated total costs to be avoided by the measure by appropriate capacity, energy and measure unit metric and in the aggregate by year;

c. estimated participation incentives by appropriate capacity, energy, and measure unit metric and in the aggregate by year;

d. how the electric public utility proposes to allocate the costs and benefits of the measure among the customer classes and jurisdictions it serves;

e. the capitalization period to allow the utility to recover all costs or those portions of the costs associated with a new program or measure to the extent that those costs are intended to produce future benefits as provided in G.S. 62-133.9(d)(1).

f. The electric public utility shall also include the estimated and known costs of measurement and verification activities pursuant to the Measurement and Verification Reporting Plan described in paragraph (ii).

(ii) Measurement and Verification Reporting Plan for New Demand-Side Management and Energy Efficiency Measures. — The electric public utility shall be responsible for the measurement and verification of energy and peak demand savings and may use the services of an independent third party for such purposes. The costs of implementing the measurement and verification process may be considered as operating costs for purposes of Commission Rule R8-69. In addition, the electric public utility shall:

a. describe the industry-accepted methods to be used to evaluate, measure, verify, and validate the energy and peak demand savings estimated in (2)(iii)c and d above;

b. provide a schedule for reporting the savings to the Commission;

c. describe the methodologies used to produce the impact estimates, as well as, if appropriate, the methodologies it considered and rejected in the interim leading to final model specification; and

d. identify any third party and include all of the costs of that third party, if the electric public utility plans to utilize an independent third party for purposes of measurement and verification.

(iii) Cost recovery mechanism. — The electric public utility shall describe the proposed method of cost recovery from its customers.

(iv) Tariffs or rates. — The electric public utility shall provide proposed tariffs or modifications to existing tariffs that will be required to implement each measure or program.

(v) Utility Incentives. — When seeking approval of new demand-side management and energy efficiency measures, the electric public utility shall indicate whether it will seek to recover any utility incentives, including, if appropriate, net lost revenues, in addition to its costs. If the electric public utility proposes recovery of utility incentives related to the proposed new demand-side management or energy efficiency measure, it shall describe the utility incentives it desires to recover and describe how its measurement and verification reporting plan will demonstrate the results achieved by the proposed measure. If the electric public utility proposes recovery of net lost revenues, it shall describe estimated net lost revenues by appropriate capacity, energy and measure unit metric and in the aggregate by year. If the electric public utility seeks recovery of utility incentives, including net lost revenues, apart from its recovery of its costs under G.S. 62-133.9, it shall file estimates of the utility incentives and the net lost revenues associated with the proposed measure for each year of the proposed recovery. If the electric public utility seeks only the recovery of net lost revenues apart from its recovery of combined costs and utility incentives, it shall file estimates of net lost revenues for each year of the proposed recovery period.

(d) Procedure.

(1) Automatic Tariff Suspension. – If an electric public utility files a proposed tariff or tariff amendment in connection with an application for approval of a measure or program, the tariff filing shall be automatically suspended pursuant to G.S. 62-134 pending investigation, review, and decision by the Commission.

(2) Service and Response. — The electric public utility or electric membership corporation filing for approval of a measure or program shall serve a copy of its filing on the Public Staff; the Attorney General; the natural gas utilities, electric public utilities, and electric membership corporations operating in the filing electric public utility's or electric membership corporation's certified territory; and any other party that has notified the electric public utility or electric

membership corporation in writing that it wishes to be served with copies of all filings. If a party consents, the electric public utility or electric membership corporation may serve it with electronic copies of all filings. Those served, and others learning of the application, shall have thirty (30) days from the date of the filing in which to petition for intervention pursuant to Rule R1-19, file a protest pursuant to Rule R1-6, or file comments on the proposed measure or program. In comments, any party may recommend approval or disapproval of the measure or program or identify any issue relative to the program application that it believes requires further investigation. The filing electric public utility or electric membership corporation shall have the opportunity to respond to the petitions, protests, or comments within ten (10) days of their filing. If any party raises an issue of material fact, the Commission shall set the matter for hearing. The Commission may determine the scope of this hearing.

(3) Notice and Schedule. — If the application is set for hearing, the Commission shall require notice, as it considers appropriate, and shall establish a procedural schedule for prefiled testimony and rebuttal testimony after a discovery period of at least 45 days. Where possible, the hearing shall be held within ninety (90) days from the application filing date.

(e) Scope of Review. — In determining whether to approve in whole or in part a new measure or program or changes to an existing measure or program, the Commission may consider any information it determines to be relevant, including any of the following issues:

(1) Whether the proposed measure or program is in the public interest and benefits the electric public utility's or electric membership corporation's overall customer body;

(2) Whether the proposed measure or program unreasonably discriminates among persons receiving or applying for the same kind and degree of service;

(3) Evidence of consideration or compensation paid by any competitor, regulated or unregulated, of the electric public utility or electric membership corporation to secure the installation or adoption of the use of such competitor's services;

(4) Whether the proposed measure or program promotes unfair or destructive competition or is inconsistent with the public policy of this State as set forth in G.S. 62-2 and G.S. 62-140; and

(5) The impact of the proposed measure or program on peak loads and load factors of the filing electric public utility or electric membership corporation, and whether it encourages energy efficiency.

(f) Cost Recovery for New Measures. —Approval of a program or measure under Commission Rule R8-68 does not constitute approval of rate recovery of the costs of the program or measure. With respect to new demand-side management and energy efficiency measures, the costs of those new measures, approved by application of this rule, that are found to be reasonable and prudently incurred shall be recovered

through the annual rider described in G.S. 62-133.9 and Rule R8-69. The Commission may consider in the annual rider proceeding whether to approve the inclusion of any utility incentive pursuant to G.S. 62-133.9(d)(2)a-c. in the annual rider.
(NCUC Docket No. E-100, Sub 113, 2/29/08; NCUC Docket No. E-100, Sub 113, 3/13/08; NCUC Docket No. E-100, Subs 113 & 121, 1/31/11.)

R8-69 COST RECOVERY FOR DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY MEASURES OF ELECTRIC PUBLIC UTILITIES

(a) Definitions.

(1) Unless listed below, the definitions of all terms used in this rule shall be as set forth in Rules R8-67 and R8-68, or if not defined therein, then as set forth in G.S. 62-133.8(a) and G.S. 62-133.9(a).

(2) "DSM/EE rider" means a charge or rate established by the Commission annually pursuant to G.S. 62-133.9(d) to allow the electric public utility to recover all reasonable and prudent costs incurred in adopting and implementing new demand-side management and energy efficiency measures after August 20, 2007, as well as, if appropriate, utility incentives, including net lost revenues.

(3) "Large commercial customer" means any commercial customer that has an annual energy usage of not less than 1,000,000 kilowatt-hours (kWh), measured in the same manner as the electric public utility that serves the commercial customer measures energy for billing purposes.

(4) "Rate period" means the period during which the DSM/EE rider established under this rule will be in effect. For each electric public utility, this period will be the same as the period during which the rider established under Rule R8-55 is in effect.

(5) "Test period" shall be the same for each public utility as its test period for purposes of Rule R8-55, unless otherwise ordered by the Commission.

(b) Recovery of Costs.

(1) Each year the Commission shall conduct a proceeding for each electric public utility to establish an annual DSM/EE rider. The DSM/EE rider shall consist of a reasonable and appropriate estimate of the expenses expected to be incurred by the electric public utility, during the rate period, for the purpose of adopting and implementing new demand-side management and energy efficiency measures previously approved pursuant to Rule R8-68. The expenses will be further modified through the use of a DSM/EE experience modification factor (DSM/EE EMF) rider. The DSM/EE EMF rider will reflect the difference between the reasonable expenses prudently incurred by the electric public utility during the test period for that purpose and the revenues that were actually realized during the test period under the DSM/EE rider then in effect. Those expenses approved for recovery shall be allocated to the North Carolina retail jurisdiction consistent with the system benefits provided by the new demand-side management and energy efficiency measures and shall be assigned to customer classes in accordance with G.S. 62-133.9(e) and (f).

(2) Upon the request of the electric public utility, the Commission shall also incorporate the experienced over-recovery or under-recovery of costs up to thirty (30) days prior to the date of the hearing in its determination of the DSM/EE

EMF rider, provided that the reasonableness and prudence of these costs shall be subject to review in the utility's next annual DSM/EE rider hearing.

(3) Pursuant to G.S. 62-130(e), any over-collection of reasonable and prudently incurred costs to be refunded to an electric public utility's customers through operation of the DSM/EE EMF rider shall include an amount of interest, at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate. The beginning date for measurement of such interest shall be the effective date of the DSM/EE EMF rider in each annual proceeding, unless otherwise determined by the Commission.

(4) The burden of proof as to whether the costs were reasonably and prudently incurred shall be on the electric public utility.

(5) Any costs incurred for adopting and implementing measures that do not constitute new demand-side management or energy efficiency measures are ineligible for recovery through the annual rider established in G.S. 62-133.9.

(6) Except as provided in (c)(3) of this rule, each electric public utility may implement deferral accounting for costs considered for recovery through the annual rider. At the time the Commission approves a new demand-side management or energy efficiency measure under Rule R8-68, the electric public utility may defer costs of adopting and implementing the new measure in accordance with the Commission's approval order under Rule R8-68. Subject to the Commission's review, the electric public utility may begin deferring the costs of adopting and implementing new demand-side management or energy efficiency measures six (6) months prior to the filing of its application for approval under Rule R8-68, except that the Commission may consider earlier deferral of development costs in exceptional cases, where such deferral is necessary to develop an energy efficiency measure. Deferral accounting, however, for any administrative costs, general costs, or other costs not directly related to a new demand-side management or energy efficiency measure must be approved prior to deferral. The balance in the deferral account, net of deferred income taxes, may accrue a return at the net-of-tax rate of return approved in the electric public utility's most recent general rate proceeding. The return so calculated will be adjusted in any rider calculation to reflect necessary recoveries of income taxes. This return is not subject to compounding. The accrual of such return of on any under-recovered or over-recovered balance set in an annual proceeding for recovery or refund through a DSM/EE EMF rider shall cease as of the effective date of the DSM/EE EMF rider in that proceeding, unless otherwise determined by the Commission. However, deferral accounting of costs shall not affect the Commission's authority under this rule to determine whether the deferred costs may be recovered.

(c) Utility Incentives.

(1) With respect to a new demand-side management or energy efficiency measure previously approved under Rule R8-68, the electric public utility may, in its annual filing, apply for recovery of any utility incentives, including, if appropriate, net lost revenues, identified in its application for

approval of the measure. The Commission shall determine the appropriate ratemaking treatment for any such utility incentives.

(2) When requesting inclusion of a utility incentive in the annual rider, the electric public utility bears the burden of proving its calculations of those utility incentives and the justification for including them in the annual rider, either through its measurement and verification reporting plan or through other relevant evidence.

(3) An electric public utility shall not be permitted to implement deferral accounting or the accrual of a return for utility incentives unless the Commission approves an annual rider that provides for recovery of an integrated amount of costs and utility incentives. In that instance, the Commission shall determine the extent to which deferral accounting and the accrual of a return will be allowed.

(d) Special Provisions for Industrial or Large Commercial Customers.

(1) Pursuant to G.S. 62-133.9(f), any industrial customer or large commercial customer may notify its electric power supplier that: (i) it has implemented or, in accordance with stated, quantifiable goals, will implement alternative demand-side management or energy efficiency measures; and (ii) it elects not to participate in demand-side management or energy efficiency measures for which cost recovery is allowed under G.S. 62-133.9. Any such customer shall be exempt from any annual rider established pursuant to this rule after the date of notification.

(2) At the time the electric public utility petitions for the annual rider, it shall provide the Commission with a list of those industrial or large commercial customers that have opted out of participation in the new demand-side management or energy efficiency measures. The electric public utility shall also provide the Commission with a listing of industrial or large commercial customers that have elected to participate in new measures after having initially notified the electric public utility that it declined to participate.

(3) Any customer that opts out but subsequently elects to participate in a new demand-side management or energy efficiency measure or program loses the right to be exempt from payment of the rider for five years or the life of the measure or program, whichever is longer. For purposes of this subsection, “life of the measure or program” means the capitalization period approved by the Commission to allow the utility to recover all costs or those portions of the costs associated with a program or measure to the extent that those costs are intended to produce future benefits as provided in G.S. 62-133.9(d)(1).

(e) Annual Proceeding.

(1) For each electric public utility, the Commission shall schedule an annual rider hearing pursuant to G.S. 62-133.9(d) to review the costs incurred by the electric public utility in the adoption and implementation of new demand-side management and energy efficiency measures during the test period, the revenues realized during the test period through the operation of the annual rider, and the costs expected to be incurred during the rate period and shall establish

annual DSM/EE and DSM/EE EMF riders to allow the electric public utility to recover all costs found by the Commission to be recoverable. The Commission may also approve, if appropriate, the recovery of utility incentives, including net lost revenues, pursuant to G.S. 62-133.9(d)(2) in the rider.

(2) The annual rider hearing for each electric public utility will be scheduled as soon as practicable after the hearing held by the Commission for the electric public utility under Rule R8-55. Each electric public utility shall file its application for recovery of costs and appropriate utility incentives at the same time that it files the information required by Rule R8-55.

(3) The DSM/EE EMF rider will remain in effect for a fixed 12-month period following establishment and will continue as a rider to rates established in any intervening general rate case proceeding.

(f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(i) Projected North Carolina retail monthly kWh sales for the rate period.

(ii) For each measure for which cost recovery is requested through the DSM/EE rider:

a. total expenses expected to be incurred during the rate period in the aggregate and broken down by type of expenditure, per appropriate capacity, energy and measure unit metric and the proposed jurisdictional allocation factors;

b. total costs that the utility does not expect to incur during the rate period as a direct result of the measure in the aggregate and broken down by type of cost, per appropriate capacity, energy and measure unit metric, and the proposed jurisdictional allocation factors, as well as any changes in the estimated future amounts since last filed with the Commission;

c. a description of the measurement and verification activities to be conducted during the rate period, including their estimated costs;

d. total expected summer and winter peak demand reduction per appropriate measure unit metric and in the aggregate;

e. total expected energy reduction in the aggregate and per appropriate measure unit metric.

(iii) For each measure for which cost recovery is requested through the DSM/EE EMF rider:

a. total expenses for the test period in the aggregate and broken down by type of expenditure, per appropriate capacity, energy and measure unit metric and the proposed jurisdictional allocation factors;

b. total costs that the utility did not incur for the test period as a direct result of the measure in the aggregate and broken down by type of cost, per appropriate capacity, energy and measure unit metric, and the proposed jurisdictional allocation factors, as well as any changes in the estimated future amounts since last filed with the Commission;

c. a description of, the results of, and the costs of all measurement and verification activities conducted in the test period;

d. total summer and winter peak demand reduction in the aggregate and per appropriate measure unit metric, as well as any changes in estimated future amounts since last filed with the Commission;

e. total energy reduction in the aggregate and per appropriate measure unit metric, as well as any changes in the estimated future amounts since last filed with the Commission;

f. a discussion of the findings and the results of the program or measure;

g. evaluations of event-based programs including the date, weather conditions, event trigger, number of customers notified and number of customers enrolled; and

h. a comparison of impact estimates presented in the measure application from the previous year, those used in reporting for previous measure years, and an explanation of significant differences in the impacts reported and those previously found or used.

(iv) For each measure for which recovery of utility incentives is requested, a detailed explanation of the method proposed for calculating those utility incentives, the actual calculation of the proposed utility incentives, and the proposed method of providing for their recovery and true-up through the annual rider. If recovery of net lost revenues is requested, the total net lost kWh sales and net lost revenues per appropriate capacity, energy, and program unit metric and in the aggregate for the test period, and the proposed jurisdictional allocation factors, as well as any changes in estimated future amounts since last filed with the Commission.

(v) Actual revenues produced by the DSM/EE rider and the DSM/EE EMF rider established by the Commission during the test period and for all available months immediately preceding the rate period.

(vi) The requested DSM/EE rider and DSM/EE EMF rider and the basis for their determination.

(vii) Projected North Carolina retail monthly kWh sales for the rate period for all industrial and large commercial accounts, in the aggregate, that are not assessed the rider charges as provided in this rule.

(viii) All workpapers supporting the calculations and adjustments described above.

(2) Each electric public utility shall file the information required under this rule, accompanied by workpapers and direct testimony and exhibits of expert witnesses supporting the information filed in this proceeding, and any change in rates proposed by the electric public utility, by the date specified in subdivision (e)(2) of this rule. An electric public utility may request a rider lower than that to which its filed information suggests that it is entitled.

(3) The electric public utility shall publish a notice of the annual hearing for two (2) successive weeks in a newspaper or newspapers having general circulation in its service area, normally beginning at least thirty (30) days prior to the hearing, notifying the public of the hearing before the Commission pursuant to G.S. 62-133.9(d) and setting forth the time and the place of the hearing.

(4) Persons having an interest in any hearing may file a petition to intervene at least 15 days prior to the date of the hearing. Petitions to intervene filed less than 15 days prior to the date of the hearing may be allowed in the discretion of the Commission for good cause shown.

(5) The Public Staff and other intervenors shall file direct testimony and exhibits of expert witnesses at least 15 days prior to the hearing date. If a petition to intervene is filed less than 15 days prior to the hearing date, it shall be accompanied by any direct testimony and exhibits of expert witnesses the intervenor intends to offer at the hearing.

(6) The electric public utility may file rebuttal testimony and exhibits of expert witnesses no later than 5 days prior to the hearing date.

(NCUC Docket No. E-100, Sub 113, 2/29/08; NCUC Docket No. E-100, Sub 113, 3/13/08; NCUC Docket No. E-100, Subs 113 & 121, 1/31/11.)

MEMBERS OF GREENCO SOLUTIONS, INC.

Albemarle Electric Membership Corporation

Brunswick Electric Membership Corporation

Cape Hatteras Electric Cooperative

Carteret-Craven Electric Cooperative

Central Electric Membership Corporation

Edgecombe-Martin County Electric Membership Corporation

Four County Electric Membership Corporation

French Broad Electric Membership Corporation

Haywood Electric Membership Corporation

Jones-Onslow Electric Membership Corporation

Lumbee River Electric Membership Corporation

Pee Dee Electric Membership Corporation

Piedmont Electric Membership Corporation

Pitt & Green Electric Membership Corporation

Randolph Electric Membership Corporation

Roanoke Electric Cooperative

South River Electric Membership Corporation

Surry-Yadkin Electric Membership Corporation

Tideland Electric Membership Corporation

Tri-County Electric Membership Corporation

Union Electric Membership Corporation

Wake Electric Membership Corporation

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